ATTACHMENT G

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT

Assessment of Available Technology for Control of NOx, CO, and VOC Emissions from Biogas-Fueled Engines

Draft Final Report

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INTRODUCTION

Rule 1110.2 establishes emission limits of NOx, VOC, and CO for stationary, non-emergency gaseous- and liquid-fueled engines, including the 55 engines in this source category, that are fueled by landfill or digester gas (biogas). The emissions from biogas engines amount to approximately 1.3 tons per day of NOx, 0.8 tons per day of VOC, and 25.6 tons per day of CO.

Rule 1110.2 was amended on February 1, 2008 to lower the emission limits of natural gas and biogas engines to BACT levels for NOx and VOC and to levels close to BACT for CO. The limits for natural gas engines at or above 500 bhp took effect on July 1, 2010, while those for natural gas engines below 500 bhp took effect on July 1, 2011. Biogas engines were given until July 1, 2012 to comply with the new limits.

Table 1. Current and Future Biogas Engine Emission Limits (ppmvd @15% O_2)

	NOx	VOC	CO
≥ 500bhp	36 x ECF*	250 x ECF* (digester) 40 (landfill)	2000
< 500 bhp	45 x ECF*	250 x ECF* (digester) 40 (landfill)	2000
Future limits[1]	*11*	*30*	*250*

*ECF is the Efficiency Correction Factor

[1] The "future" limits are those that were originally scheduled to go into effect July 1, 2012, but did not go into effect, as explained below.

The future emission levels in Table 1 are based on BACT limits for lean-burn natural gas engines, which in g/bhp-hr are 0.15 for NOx, 0.6 for CO, and 0.15 for VOC. The current BACT limits for biogas engines are much higher. Expressed in g/bhp-hr, they are 0.6 for NOx, 2.5 for CO, and 0.8 for VOC. Figure 1 highlights this difference.
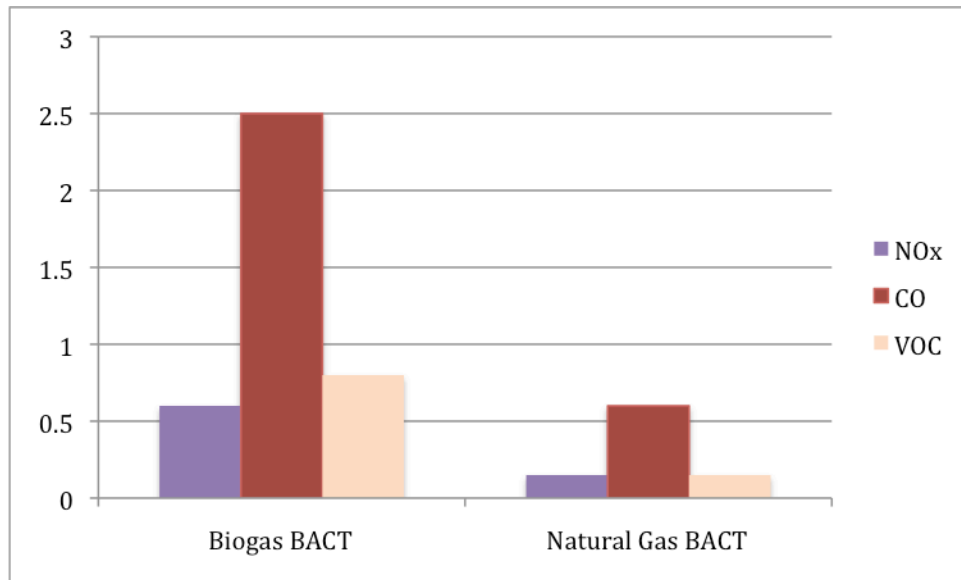
Figure 1. Biogas vs. Natural Gas BACT in g/bhp-hr

The BACT limits for lean-burn natural gas engines have been in effect for many years and many installations are complying with these limits by way of oxidation catalysts for CO and VOC control and selective catalytic reduction (SCR) for NOx control.

The amendment and adopting resolutions of Rule 1110.2 in 2008 directed staff to conduct a Technology Assessment to address the availability, feasibility, cost-effectiveness, compliance schedule, and global warming gas impacts of biogas engine control technologies and report back to the Governing Board no later than July 2010. Immediately after the 2008 amendment, staff began work on the Technology Assessment and followed the progress of several technology demonstration projects.

1. *OCSD (Orange County Sanitation District).* A year-long pilot study utilizing a digester gas cleanup system (non-regenerative) and catalytic oxidation with selective catalytic reduction.

2. *EMWD (Eastern Municipal Water District).* Two selective non-catalytic reduction technologies applied to water and wastewater treatment applications. One technology (NOxTech) was installed at a pumping station with three natural gas-fired engines. The other technology utilizes fuel cells to produce power from digester gas at two of its wastewater treatment facilities.

3. *IEUA* *(Inland Empire Utilities Agency)*. Fuel cells have been installed at this digester gas facility to eventually replace the IC engines currently installed.

4. *Ox Mountain*. This installation in the Bay Area uses biogas cleanup, catalytic oxidation, and SCR to produce power from landfill gas. The technology is similar to OCSD's in its post combustion after treatment, but uses a regenerative siloxane removal system to clean the landfill gas.

In July 2010, staff presented to the Governing Board an Interim Technology Assessment which summarized the biogas cleanup and biogas engine control technologies to date and the status of on-going demonstration projects. Due to the delays caused by the permit moratorium in 2009, the release of another report was recommended upon the completion of these projects. The Interim Technology Assessment concluded that feasible, cost-effective technology that could support the feasibility of the July 2012 emission limits is available, but that the delay in the demonstration projects would likely necessitate an adjustment to the July 1, 2012 compliance date of Rule 1110.2.

The proposed amendments for Rule 1110.2 provide an adjustment to the July 1, 2012 compliance date. Since July 2010, District staff has received ample evidence in support of the feasibility of biogas engine control technology and the feasibility of the compliance limits to complete the Technology Assessment. This Final Technology Assessment discusses the technologies pertinent to biogas engines for complying with these emission limits.

BIOGAS CLEANUP

For natural gas engines, the use of catalyst after-treatment is an effective method for pollutant control. However, Rule 1110.2 did not lower the emission limits for biogas engines at the same time as natural gas engines because the same catalyst controls for natural gas engines would experience fouling when exposed to the combustion products of biogas. It was learned that the cause of the catalyst fouling was due to a specific impurity in the gas stream. These impurities are now known as siloxanes.

In the 2010 Interim Technology Assessment, the impacts of siloxanes were highlighted and evaluated in terms of facility-specific levels and control costs. The conclusion was that by installing an appropriately designed biogas cleanup system, an engine along with its post-combustion control system can function properly.

A prime concern for many biogas engine operators is the quality of the fuel going into the engines. Biogas, whether coming from a wastewater treatment plant digester or from a

landfill, has many impurities, including but not limited to sulfur-containing compounds and siloxanes, that require some sort of treatment. If left untreated, raw biogas can damage engine components that will result in more maintenance and ultimately, reduced longevity of an engine. Siloxanes crystallize at elevated temperatures and can become deposited even in fuel lines. Upon combustion, siloxanes oxidize and more commonly become deposited on engine parts (pistons, piston sleeves, and valves) as silicon dioxide (SiO_2). As a result, more frequent major maintenance on engines is required so that these deposits can be cleaned up from within the engine. These major repairs involve the removal of the engine head to access the internal valves and piston shafts. Failure to perform this kind of maintenance can result in catastrophic damage to an engine. The pretreatment of biogas is even more critical with the employment of catalyst-based after-treatment technologies downstream from the engines. If left untreated, these siloxane impurities can negatively affect the catalysts. The catalyst active sites can become masked by the deposition of the silica, therefore reducing the efficiency of the entire catalyst for pollutant removal.

Since the release of the Interim Technology Assessment and the installation of several biogas cleanup systems in the basin, it has been established that biogas cleanup cannot consist of siloxane removal only. Depending on the source of the raw biogas, some facilities have biogas profiles that contain varying levels of other pollutants, such as VOCs and sulfur compounds. Also, with the installation of fuel cells and gas turbines operating on biogas in the basin, the fuel specifications for these sophisticated units are extremely stringent for impurities. Biogas entering these systems must be completely cleaned of many impurities to guarantee proper performance.

Some facilities currently have practically no gas cleanup while most others employ some sort of gas cleanup for improved engine maintenance. On the other hand, a few facilities already employ a complete biogas cleanup system for protection of post combustion catalysts or turbines. Many facilities often utilize a typical cleanup system that results in moisture and particulate removal only. The previously mentioned demonstration project at the Orange County Sanitation District (OCSD) utilized the facility's existing compressors and chillers, while relying on a single activated carbon vessel as the sole source for siloxane removal. This digester gas cleaning system (DGCS) was installed (supplied by Applied Filter Technology) to remove contaminants from the digester gas before combustion and the potential for carbon media breakthrough was routinely monitored throughout the pilot study. Depending on the existing level of contaminants, some facilities may have to install complete, skid-mounted gas cleanup systems that can include water and particulate removal filters, sorbent vessels for H_2S and siloxane

removal, compressors, chillers, coalescing filters, and vessels for VOC and sulfur species removal if necessary.

As described in the Interim Technology Assessment, there are two types of siloxane removal systems: regenerative and non-regenerative. Regenerative siloxane removal systems do not require constant removal of the sorbent material from the vessels. The vessels are set up in pairs and while the media in the first vessel is regenerated using a heated purge gas the second vessel handles the siloxane cleanup load. The regeneration cycle then switches to the second vessel when it nears its removal efficiency limit, while the first vessel now handles the gas cleanup.

The regenerative siloxane removal system at Ox Mountain Landfill is the only installation that currently uses this type of system for the protection of a post-combustion catalyst on a landfill gas-fired engine. Ox Mountain Landfill is located at Half Moon Bay, CA which is within the Bay Area Air Quality Management District's (BAAQMD) jurisdiction. The landfill gas to energy site (operated by Ameresco) has six GE-Jenbacher engines, each rated at 2677 bhp, that are fired on landfill gas. All six engines have been retrofitted with oxidation catalysts, while one of the engines also has an SCR system. The gas cleanup system with regenerative siloxane removal processes the gas for all the engines. It employs a Temperature Swing Adsorption (TSA) regenerative siloxane removal system manufactured by GE-Jenbacher. Eight pairs of adsorption beds (16 total vessels) using regenerative activated carbon are employed at this installation. AlO_2 is an alternate media that is used as other locations. Electric coils in the vessel annular space heat the carbon media while clean biogas is flushed through the beds as a purge gas. The purge gas is then combusted by a small, enclosed flare. At Ox Mountain, eight vessels are actively removing impurities while the other eight are being regenerated. The parasitic load of the TSA system is obviously higher when actively heating the vessels, but it is about 5% of the total plant's output. The gas cleanup and oxidation catalyst/SCR was commissioned in 2009 and has shown to be very effective in the removal of siloxanes from the landfill gas. Performance data from 2009 to 2011 shows that the system is removing between 95 and 99 percent of inlet siloxanes (inlet between 7 and 10 ppmv with reported spikes between 25 and 50 ppmv), while no siloxane breakthrough has ever occurred at this facility. The gas is tested periodically, while carbon media and engine samples are also analyzed. Ox Mountain's TSA media requires a complete replacement around every twelve months, but some installations can go longer before media replacement. Every installation will have its own unique gas profile, so the regeneration cycles will be specific for every location and will take start-up time and

testing to optimize. The engines at Ox Mountain have also enjoyed the benefit of less frequent maintenance, and can run for much longer between major overhauls.

Non-regenerative siloxane removal systems require periodic replacement of the sorbent material (activated carbon or silica gel) once it is spent. Additionally, the use of two beds is more beneficial in that one bed can still be used while the other is recharged with fresh sorbent and vice versa. These systems are sized to handle the site-specific flow rate into all the facility's biogas engines and the siloxane load. Larger vessels are required for higher flow rate applications and a higher frequency of sorbent replacement is required for biogas streams with higher levels of siloxanes. A redundant dual-bed system enables the handling of intermittent spikes.

The following two tables (Table 2 and Table 3) are updates from the Interim Technology Assessment regarding catalyst performance with the protection of biogas cleanup with non-regenerative siloxane removal systems located both inside and outside of SCAQMD jurisdiction. All of the systems have been successfully operating with varying levels of biogas and the oxidation/SCR catalysts have been protected.

The demonstration project at OCSD has proven that a non-regenerative siloxane treatment system can condition biogas and protect biogas engines and post combustion catalysts. The gas cleanup system removed siloxanes, VOCs, and sulfur compounds effectively without any breakthrough to the engines. An added benefit was realized in that there was a reduction in the engine maintenance due to the cleaner biogas that was being combusted. Furthermore, the result was a cost savings for engine maintenance, increased engine uptime, and longer maintenance intervals. The OCSD demonstration project saved $43,547 in engine maintenance costs annually with the use and careful monitoring of the gas cleanup system. Additionally, the gas cleanup system from its catalytic oxidizer pilot study in 2007 is still in operation today based on the performance improvements to the engine and the reduced maintenance costs.

With the demonstration project at OCSD completed and the installation at Ox Mountain in its third year, the employment of both regenerative and non-regenerative siloxane removal systems for the protection of post-combustion catalyst has been proven to be feasible. Performance data from both installations demonstrates effective siloxane removal for both digester and landfill gas applications.

Table 2. Non-Regenerative Siloxane Removal Systems Located in SCAQMD

System	Type of Biogas	Size (SCFM Biogas)	Combustion Device	Natural Gas Blend in Combustion Device	Catalyst(s)	Startup Year	Operating History	Status	Comments
Orange County Sanitation District	Digester Gas	850	IC Engine	10% Max	Oxidation	2006	Engine operation has been normal	Operating	Similar system tested in pilot study in 2010
Brea Parent 2007, LLC	Landfill Gas	3,000	IC Engine (3)	None	Oxidation	2006	Engine operation has been normal	Operating	Similar system will be used on new turbine plant with Oxidation/SCR catalysts
City of Industry	Landfill Gas	267	IC Engine	73%+	SCR and Oxidation	2005	Seasonal Operation	Use of biogas ended 2007	Methane content too low
UCLA	Landfill Gas	3,472	Gas Turbine	78%+	SCR and Oxidation	1994	Turbine operation has been normal	Operating	
LADWP Scattergood Generating Station	Digester Gas	5,555	Boiler (2)	89%+	SCR and Oxidation	2001	Boilers have been in normal operation	Operating	

Table 3. Non-Regenerative Siloxane Removal Systems Located Outside of SCAQMD

System	Type of Biogas	Size (SCFM Biogas)	Combustion Device	Natural Gas Blend in Combustion Device	Catalyst(s)	Startup Year	Operating History	Status	Comments
Carson Cogen (Elk Grove, CA)	Digester Gas	2,500	Gas Turbine	75%	SCR	1996	Turbine operation has been normal	Operating	Digester gas now is further cleaned and transferred via natural gas pipeline to another power plant
Bergen County Utilities Authority (NJ)	Digester Gas	~~300~~800	IC Engine	~~10-20%~~None	Oxidation	200~~8~~2	IC Engine operation was normal	~~Operating~~Awaiting Status	~~CO limit is 27.1 ppmv, so more frequent catalyst replacements are required~~
City of Eugene Wastewater Treatment Plant	Digester Gas	240	IC Engine	None	Oxidation	2004	IC Engine operation has been normal	Awaiting Status	

CATALYTIC OXIDATION/SELECTIVE CATALYTIC REDUCTION

A proven and effective means for CO, VOC, and NOx control among natural gas fueled lean-burn engines is catalytic oxidation with selective catalytic reduction (SCR). If the raw biogas is cleaned sufficiently and effectively, there is no danger of fouling any post combustion catalyst by siloxane deposition.

Catalytic oxidation removes CO and VOC upon its contact with the catalyst. Oxidation catalysts contain precious metals that react incoming CO and VOC with oxygen to produce CO_2 and water vapor. Reductions greater than 90% in CO and VOC emissions are typical with this technology.

SCR can be used with lean-burn engines since the higher oxygen concentrations in the exhaust preclude the use of less costly nonselective catalytic reduction (NSCR or three-way catalysts). SCR requires the injection of urea to react with the NOx in the engine's flue gas, and is very effective in its removal. The SCR catalyst promotes the reaction of ammonia with NOx and oxygen, with water vapor and nitrogen gas being the end products.

The demonstration project at OCSD has shown with certainty that this combination of post combustion systems (oxidation catalyst and SCR) is capable of handling treated biogas combustion exhaust for multi-pollutant control. The District issued a grant to OCSD in 2009 (*SCAQMD Contract #10114*) to support the pilot test study of Engine No. 1 (in Fountain Valley) with a catalytic oxidizer/SCR with digester gas cleanup, and the operation of the pilot study was granted a Permit to Construct/Operate for an Experimental Research Project by SCAQMD (Application Number 497717) in November 2009. The construction and installation of the pilot study equipment commenced in October 2009; the pilot study testing officially began on April 1, 2010 and officially ended on March 31, 2011. A continuous emission monitoring system (CEMS) was used for analysis of NOx and CO emissions. The sampling methods for several other pollutants are listed in Table 4.

Table 4. Sampling Methods for Pollutants in OCSD Pilot Study

Pollutant	Sampling Method
CO	CEMS, Portable Analyzer, SCAQMD Method 100.1
VOC	SCAQMD Methods 25.1/25.3
NOx	CEMS, Portable Analyzer, SCAQMD Method 100.1
Aldehydes	Modified CARB Method 430, SCAQMD Method 323 (Formaldehyde)
Free Ammonia (Ammonia slip)	Modified SCAQMD Method 207.1 and Draeger® tubes

The results of the pilot study are as follows:

1. NOx emissions averaged around 7 ppmv, well below the proposed rule limit of 11 ppmv by over 35 percent.

2. VOC emissions averaged around 3.6 ppmv, well below the proposed rule limit of 30 ppmv by 88 percent.

3. CO emissions averaged around 7.5 ppmv, well below the proposed rule limit of 250 ppmv by 97 percent.

The maximum VOC level reached was around 5 ppmv, while the maximum CO level reached was 42 ppmv. The results were based on a 15-minute averaging time, per the current rule requirements. There were some NOx excursions during the testing period, however, and these accounted for around 4% of the total 15-minute measurement periods, using both valid and invalid data. Exceedances that were attributed to engine start-up (first 30 minutes), operational issues (breakdowns), and system adjustments were excluded and labeled invalid. Only validated data was used to account for the excursions, and these accounted for 0.9% of the total time periods.

Data from the OCSD demonstration project indicates that the emission control system reduces emissions of air toxics. The gas cleanup system removes acid gases, sulfur compounds, volatile air toxics, including aromatic and chlorinated organic compounds, and particulates that contain toxic compounds. OCSD took samples of digester gas before and after the gas cleanup system. The test program analyzed 66 organic compounds including 16 air toxics. OCSD test results indicate that concentrations of air

toxic compounds are reduced, non-detectable, or not changed. Emissions of aromatic hydrocarbons, precursors to formation of dioxins and furans, are significantly reduced. Emission of formaldehyde from the engine, the most significant source of risk from the facility, was reduced by 98% to below 1 ppm. This reduction is achieved by the oxidation catalyst. This combination of a gas cleanup system, oxidation catalyst and SCR will not increase emissions of air toxics and reduces the major source of risk from continued operation of these engines. The CEQA document for proposed amended rule 1110.2 provides additional information of air toxic impacts for the proposed rule.

OCSD's final report recommended a less restrictive averaging time for biogas engines as a result of the pilot study data. Staff analyzed several possible averaging times to determine an acceptable time period that would address the exceedances without affecting the mass emissions. Using OCSD's 15-minute raw data from its pilot study, several averaging times were evaluated; the results listed in Table 5. Consistent with OCSD's analysis, only validated 15-minute block average data was used (not including exceedances due to start-up, atypical operating conditions, breakdowns, and system adjustments).

Table 5. OCSD Pilot Study NOx CEMS Data

Averaging Time (hours)	Number of 15-minute periods >11 ppmv
0.25	182
1	18
2	4
3	4
4	4
6	2
8	0
10	0
12	0
16	0
24	0

Staff found that an 8 hour block-averaging time would address OCSD's exceedances above 11 ppmv. As a result of this analysis, staff is proposing for engines with controls achieving superior performance in terms of reducing emissions, a 24~~12~~ hour averaging time to be able to comfortably address NOx exceedances without affecting the overall mass emissions. This longer averaging time will be extended to CO as well in the Staff proposal. With the results obtained, the OCSD project has demonstrated that this type of control technology can prove effective for meeting the proposed Rule 1110.2 limits.

A consideration that is always taken when applying SCR technology is the potential for ammonia slip when injecting urea into any exhaust gas stream. Ammonia is a toxic compound, and careful control must be taken in order to prevent excess amounts from escaping out of the stack. A limit of 10 ppm was assigned on the project's research permit and the maximum level emitted was 5 ppm during the pilot demonstration. An important factor when adjusting urea injection rates is ensuring that sufficient amounts of urea are injected in response to the engine's load demand and/or NOx level in real time or as close to real time as possible. This is to prevent too much ammonia from escaping out of the stack while simultaneously preventing too little urea from entering the exhaust stream that can result in an increase in NOx out of the stack.

An installation that also uses an oxidation catalyst/SCR technology, but applied to a landfill, is located at the Ox Mountain Landfill in northern California (Figure 2). Ameresco is the facility operator of the biogas engines at this location. One of its six GE-Jenbacher engines on-site was outfitted with both a catalytic oxidizer and SCR system in 2009 and has been operating since. Data that has been obtained from the BAAQMD has shown that the proposed Rule 1110.2 limits are achievable. CEMS data obtained from 2010 shows a consistent performance level that is consistent with OCSD's pilot study. In addition, monthly emission data shows that the proposed emissions limits are being achieved on an average mass per brake horsepower hour basis. The engines experienced some problems soon after startup, but the catalysts have performed effectively since 2009. The oxidation catalyst employs a guard bed upstream of the catalyst to aid in protection from harmful contaminants. The SCR catalyst has not been replaced since start-up, and has yielded efficient NOx removal for over 26,000 hours. The NOx excursions above 11 ppm throughout the operation of this installation have been attributed to operational problems with the engines, the SCR urea injection system, and monitoring problems. There are many moving parts in a urea injection system and in CEMS equipment, so problems were experienced with plugged nozzles, condensation in sampling lines, sample pump failures, and NOx cell failures that led to NOx events above 11 ppmv. From Ameresco's experience at Ox Mountain, the oxidation catalyst has

experienced decreased performance over time, but not above our proposed compliance limit of 250 ppmv. Engine wear has been suspected as the cause from the catalyst manufacturer, but there has been no evidence of any siloxane breakthrough or siloxane buildup at the oxidation catalysts for any of the six units.

Several biogas engine installations in the San Joaquin Valley are achieving compliant emissions today, running on dairy digester gas. Two installations (one at a winery and another at a dairy) are meeting the 11 ppmv NOx limit, but these engines are rich burn engines, and operate with NSCR post combustion controls. The source test results for NOx corrected to 15% O_2 ranged from 1 to 10 ppmv for those engines. However, another installation for a lean burn engine at a dairy is achieving the proposed 11 ppmv NOx limit with SCR. The most recent source test resulted in a NOx concentration of 5.63 ppmv @15% O_2 (a 93% NOx reduction).

Figure 2. Ox Mountain's Landfill Gas to Energy Facility in Half Moon Bay, CA

NOXTECH

NOxTech is another post combustion control technology which provides a selective non-catalytic reduction, does not require gas cleanup, and is capable of achieving multi-pollutant control of NOx, VOC, and CO. Engine exhaust gases enter the unit where the temperature is raised by a heat exchanger. The gases then enter a reaction chamber where a small amount of the engine's fuel is added to raise the gas temperature to 1400-1500°F. At this temperature in the reaction chamber, NOx reduction can occur using urea injection, while CO and VOC are simultaneously incinerated. The system is

designed to handle biogas that is of a lower BTU content than higher BTU natural gas. Natural gas has a BTU of 1,050 BTU per cubic foot, while biogas has a BTU range (depending of the methane content) of approximately 650 BTU per cubic foot.
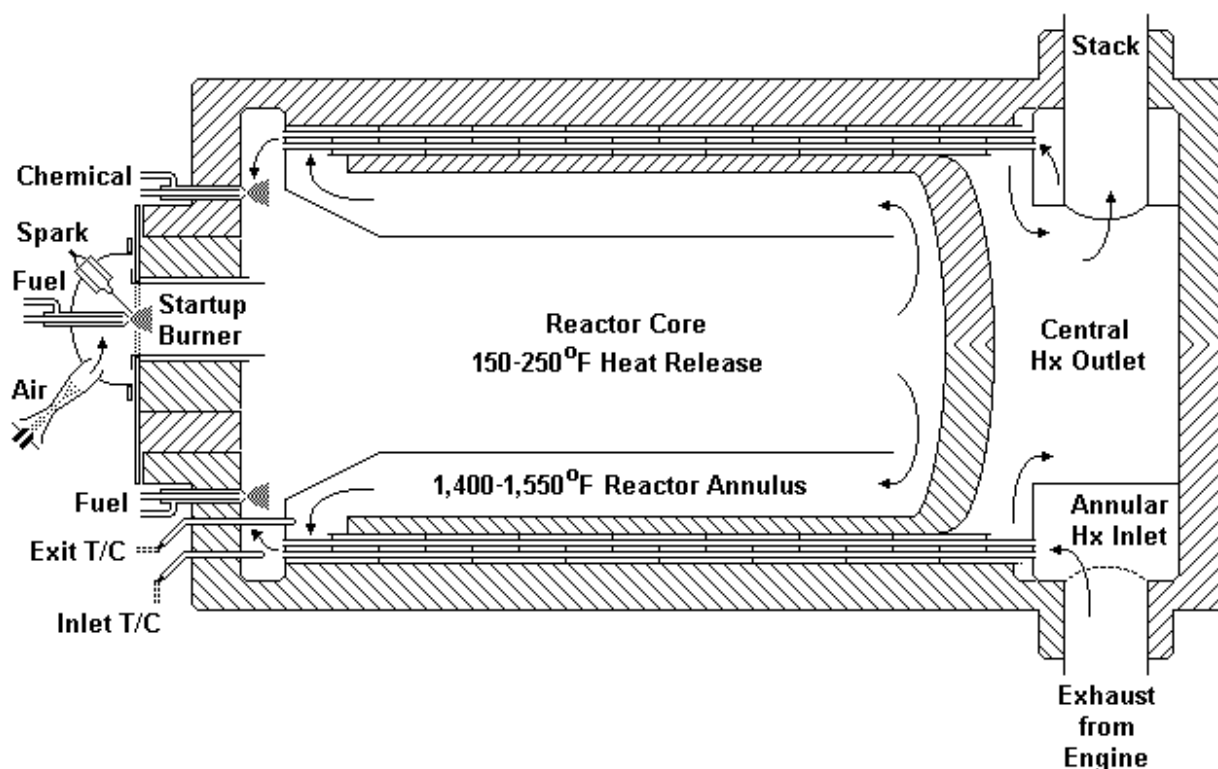
Figure 3. NOxTech System

As mentioned in the Interim Technology Assessment, a full-scale demonstration of this technology occurred at Woodville Landfill in Tulare starting in 2006, which achieved favorable results. The NOxTech unit was able to achieve NOx, CO, and VOC emissions below the proposed rule limits while running on landfill gas and in combination with a diesel engine to produce more exhaust flow. This project operated for four and a half years until the landfill was no longer able to provide sufficient gas to the engine. Two NOxTech units were operated by Southern California Edison (SCE) on diesel engines on Catalina Island from 1995 to 2001. Staff has again requested information from SCE regarding its experience and performance from this demonstration project. In May 2010, Eastern Municipal Water District (EMWD) installed a NOxTech unit at its Mills Pumping Station in Riverside. This site operates three natural gas fired internal

combustion engines and the NOxTech unit is capable of handling the exhaust gas streams for multiple engines up to a maximum total rating of 1.5 MW (approximately 2000 bhp, depending on efficiency). While originally designed to treat exhaust gases from biogas engines, EMWD opted to test the NOxTech system with its natural gas-powered engines. The NOxTech system installed downstream of natural gas-powered engines at EMWD experienced some setbacks and was not able to achieve NOx levels that were in compliance with the proposed 11 ppmv rule limit in 2011 because the system was operating at higher than expected temperatures, resulting in higher than expected thermal NOx formation. The combustion of a higher BTU natural gas fuel also burns more quickly, elevating the exhaust temperatures. A variance was granted by the AQMD for the installation and additional testing of an Exhaust Gas Recirculation (EGR) system that is designed to lower the temperature enough to prevent excess NOx formation. This enhanced system commenced testing in April 2012 and has shown some promising results. The system is still being optimized to be able to consistently perform at the proposed emission levels. The installation of a new EGR fan this year is expected to handle the elevated exhaust temperatures in order to provide more recirculated exhaust gas to the unit and lower the NOx emissions further. A second NOxTech unit is set to begin installed to control the construction at the EMWD Temecula facility's digester gas-fired engines by the end oflater this year.

For engines larger than 1.5 MW, an additional unit is required to handle the flow while a third unit is required for engines larger than 3 MW. Unlike with EMWD, a landfill application would not require an EGR system because there typically is no natural gas backup fuel to run through the unit and because of the lower BTU content of the landfill gas.

A NOxTech system can be a less costly installation that a traditional catalytic oxidation/SCR installation due in large part to the anticipated decreased operations and maintenance (O&M) costs. Periodic sorbent and catalyst replacements are a significant portion of the O&M costs incurred with the operation of a catalytic oxidation/SCR system. While urea injection is still a required component of a NOxTech system, it eliminates the need for any gas cleanup sorbents and post combustion catalysts.

ALTERNATIVE TECHNOLOGIES

This section provides a brief description o~~fn~~ alternative technologies that can be utilized to produce power from biogas with a much lower criteria pollutant emissions profile than that of biogas-fueled IC engines.

<u>Fuel Cells</u>

Fuel cells are an emerging technology capable of producing power with very low pollutant emissions without the utilization of combustion. In fact, fuel cells can produce electricity much more efficiently (between 45-50% efficiency) than combustion-based engines and turbines.

While there are a variety of fuel cell types available, fuel cells for biogas applicability use a molten carbonate cell to create an electrochemical reaction with the inlet biogas at the anode and oxygen from air at the cathode. Hydrogen is created in a reforming process at the anode, while carbonate ions are created at the cathode. The hydrogen gas reacts with the carbonate ions to produce water and electrons. These electrons flow through an external circuit that produces the electricity for the power plant.

Hydrocarbon Fuel

Steam

INTERNAL REFORMING
$CH_4 + 2H_2O \rightarrow 4H_2 + CO_2$

ANODE
$4H_2 + 4CO_3^{=} \rightarrow 4H_2O + 4CO_2 + 8e^{-}$

CATALYST

ELECTROLYTE

CATALYST

CATHODE
$2O_2 + 4CO_2 + 8e^{-} \rightarrow 4CO_3^{=}$

Air
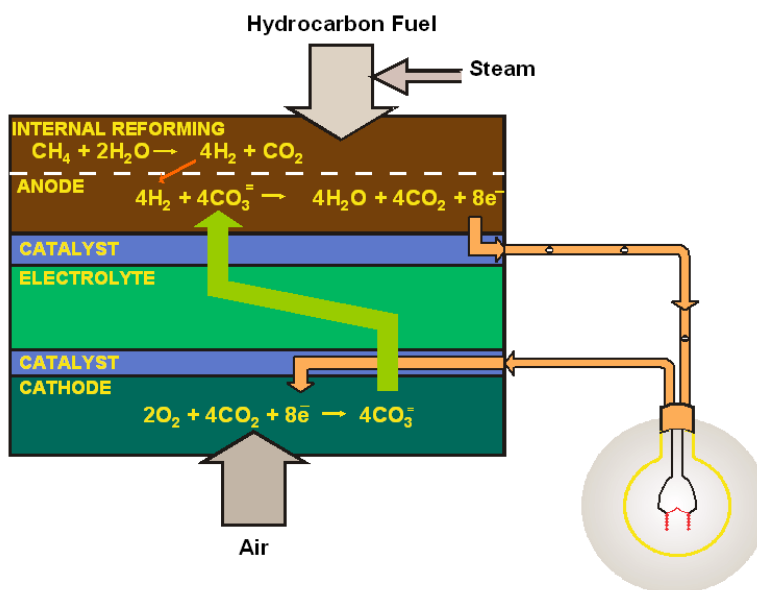
Figure 4. Fuel Cell Chemistry for Power Generation

These electrochemical reactions are produced in individual molten carbonate electrolyte stacks. The stacks are modular in design, so the total power production capacity of the generating plant can be tailored to accommodate several fuel cell stacks to meet the desired power output. The heat generated by the fuel cells can also be recovered and

used to provide process heat. For instance, the recovered heat can be used to supply heat to a wastewater treatment plant's anaerobic digesters. The fuel cell stacks, however, are sensitive to impurities, so a gas cleanup system is critical to maintain the performance of the fuel cell stacks. Siloxanes, particularly, can foul a fuel cell.

There are many fuel cell installations that run on natural gas, but the activity of digester gas fuel cells in California is significant. There are five installations in the basin located at wastewater treatment plants that are designed to operate on biogas from anaerobic digesters. EMWD has installed a fuel cell power generating facility at the Moreno Valley Regional Water Reclamation Facility and at the Perris Valley facility, while the City of Rialto has also installed a digester gas fuel cell. The City of Riverside has installed a fuel cell system at its wastewater treatment plant and Inland Empire Utilities Agency (IEUA) has completed construction of a 2.8 MW fuel cell plant at its regional plant in Ontario that began~~will begin~~ operating in June 2012 on natural gas, while digester gas will be gradually introduced into the system. It is the largest fuel cell that will be operating in the state. The installations at EMWD Moreno Valley and the City of Riverside have encountered some issues with the early design fuel cells. Specifically, the stacks were not producing the electrical output they are rated for. Fuel Cell Energy (FCE), the equipment manufacturer, is currently in the process of negotiations with the facility operator, which would involve replacing the fuel cell stacks at Riverside. EMWD Moreno Valley has restacked the fuel cells and is currently operating. It was found that the cause for the decreased fuel cell stack life was from poisoning by sulfur compounds that the gas cleanup system was not removing sufficiently. FCE now offers to handle the procurement of the gas treatment skid at the time a fuel cell is purchased along with its servicing, as well as aiding in the selection of a third party gas treatment vendor if an operator desires.

Additionally, there are 2 installations in the San Joaquin Valley in Tulare and Turlock. The Turlock installation is currently down because of a lack of digester gas fuel. Two installations are in the Bay Area at Dublin San Ramon (operating) and in San Jose (in the commissioning phase). There is also an installation in Oxnard that is operating well and in San Diego, a group of units will be started up. Fuel~~s~~ cells installed at wastewater treatment plants can take advantage of SGIP (Self-Generation Incentive Program) funds to offset the capital costs of installation.

An installation under a research permit is also currently underway at OCSD. This unit operates primarily on anaerobic digester gas with the ability to also run on natural gas or a blend of both. It is an experimental installation because the fuel cell operates in

conjunction with a hydrogen recovery unit that sends the recovered hydrogen gas to a nearby hydrogen fueling station for use by the public. This project is a collaboration of the United States Department of Energy (DOE), CARB, Air Products and Chemicals, and Fuel Cell Energy. It is expected to operate until 2014 and is intended to demonstrate an alternative energy source while reducing energy costs and reducing emissions. This fuel cell utilizes a gas cleanup system that removes sulfur compounds and, to date, has resulted in satisfactory performance of the fuel cell.

Flex Energy

Flex Energy is a system that combines microturbine technology with that of regenerative thermal oxidation to produce power with an ultra low emissions profile and without the necessity of biogas cleanup. The system is capable of taking low BTU content biogas that would be otherwise incombustible by any engine or turbine and diluting it before introducing it to a flameless thermal oxidizer that raises the temperature to destroy VOC and CO. The thermal oxidizer's temperature is also not raised so high as to facilitate the formation of thermal NOx. This process results in the consumption of methane gas without the pollutants from traditional combustion.

An open landfill will produce gas with a more or less constant amount of methane, roughly 50%. The other 50% is typically CO_2. However, once a landfill ceases to accept municipal solid waste, the amount of gas produced by the landfill will begin to decay gradually. A typical internal combustion engine that runs on landfill gas will struggle if the methane content of the biogas drops below 35-40%. Landfills that produce gas with a methane content lower than what an engine can use will typically send the gas to a flare for combustion. An advantage of the Flex Energy system is that it is capable of handling biogas with a methane content similar to what an engine consumes down to a level that is outside an engine's range of consumption. A Flex Energy system can consume landfill gas well after a landfill closes and well after an engine ceases operation due to the low methane content.

Another advantage with this type of system is that it does not require a fuel cleanup system for siloxanes and other impurities. Like the fuel cells, these systems can be modularly applied, based on the inlet characteristics of the biogas and desired power output.

Figure 5. Flex Energy FP250 Flex Powerstation

A pilot study of a Flex Energy installation was recently successfully completed at Lamb Canyon Landfill in Riverside County, CA. A Flex Energy installation is currently collecting data at a landfill in Fort Benning, GA, while approval has been granted for another installation at the Santiago Canyon Landfill in Orange County, set to begin operating later this year.

H_2 Assisted Lean Operation (HALO)

This emerging technology is based on injecting hydrogen gas into the inlet biogas stream before introduction into the engine's combustion chamber. Three to six percent hydrogen gas by mass in the fuel stream is sufficient to extend the lean limit combustion stability for the biogas fuel. Hydrogen's rapid combustion speed, wider combustion limit, and low ignition limit allows for a reduction in the exhaust emissions. There is no need for gas cleanup with the system and it takes up about a cubic meter of space. Some natural

gas is required as feedstock for hydrogen production, but produces additional electrical output and heat that can benefit a biogas facility that utilizes waste heat. The addition of hydrogen reduces hydrocarbon and CO emissions, while the leaner burning fuel lowers the combustion temperature and, therefore, lowers NOx formation.

There is no need for gas cleanup or catalytic after-treatment with hydrogen injection and it has been tested by several engine manufacturers on natural gas engines. An added benefit is also an increase in the efficiency of an engine with hydrogen enrichment. A project with the City of San Bernardino Municipal Water Department is expected to commence at the latter part of 2012 on its two, 999 bhp, cogeneration engines.

Other Combustion Technologies

Traditional gas turbines, boilers and flares fall under this category. Several landfills in the basin currently employ the use of gas turbines for the combustion of the biogas and also require extensive gas cleanup to protect the turbine blades from siloxane buildup. For example, the Calabasas Landfill operated by Los Angeles County Sanitation District and the Brea-Olinda Landfill currently use turbine technology with gas cleanup for handling landfill produced biogas. The Chiquita Canyon Landfill installation, operated by Ameresco, uses a TSA gas cleanup system similar to the one at Ox Mountain and is currently in the optimization phase. Traditional boilers can also process biogas and currently are being used by both landfills and wastewater treatment plants across the basin. For example, if a facility that operates both engines and boilers elects to shut down its engines, the remaining biogas may be handled by its boilers and any excess can be routed to the facility flare, if necessary. Boilers are less sensitive to impurities, do not require extensive gas cleanup, and can provide waste heat. The last resort for any facility that handles biogas, but cannot combust it because of an insufficient quantity or due to equipment decommissioning, would be to flare. With flaring, a facility can achieve VOC destruction from combustion, while many newer BACT flares achieve low NOx emissions. However, there are some possible CO_2 emission impacts from a greenhouse gas perspective and these will be discussed in another section of this document. There are also systems available that recover the heat from a flare for process heat or even for electrical generation. ABUTEC has produced a heat recovery flare that captures the waste heat for process utilization and a unit by UTC Power uses an organic Rankine cycle to recover the heat from a flare and produce up to 200 kW of electrical power. Figure 6 shows a comparison between source test average emissions among different technologies. Boilers, gas turbines, and microturbines overall have lower emission profiles than IC engines.

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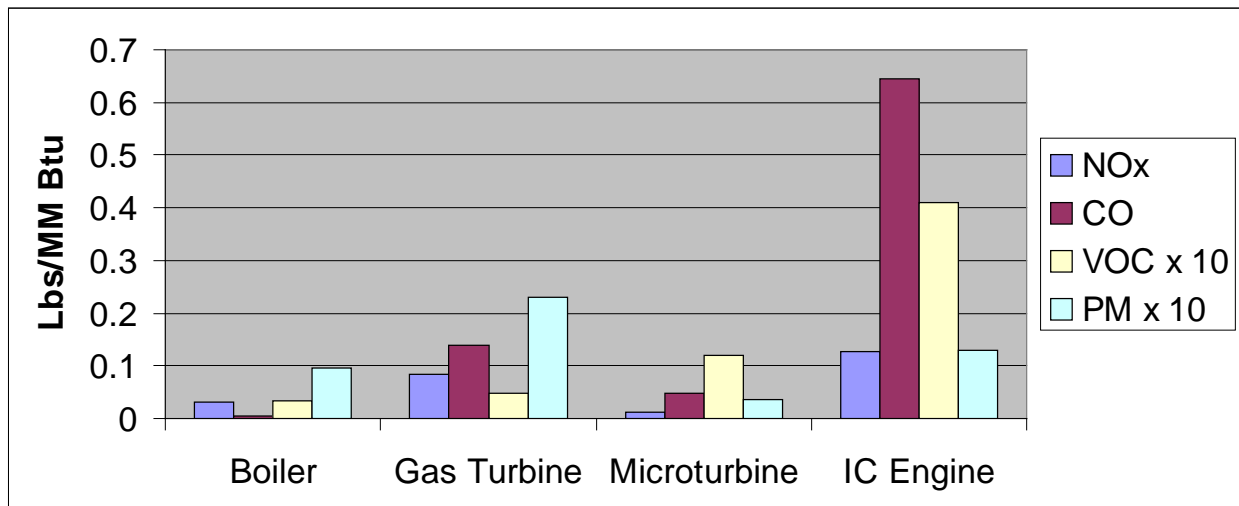
Figure 6. Emissions Comparison Among Different Biogas Electric Generation Technologies

COST AND COST EFFECTIVENESS

The cost and cost effectiveness analysis for this report relies on real data obtained from OCSD demonstration project. The pilot study demonstration project at OCSD is an example of an achieved in practice installation that has produced favorable results and that is cost effective. This installation used a digester gas cleanup system with a catalytic oxidizer and SCR for post-combustion emissions controls. In OCSD's case, additional structural work was required to support the placement of the catalytic oxidizer and SCR units. An overhead steel platform had to be constructed to support the equipment while allowing vehicle traffic to proceed underneath and to allow for urea deliveries.

The capital costs included the supporting steel necessary for the platform construction, while the annual operating costs included digester gas cleaning media replacement, oxidation catalyst and SCR catalyst replacement, and urea replacement. As a result of the gas cleanup system providing cleaner biogas to the engine, subsequent O&M costs to the engine itself were reduced as well as the frequency of maintenance operations.

The original vendor guarantee was three years for the catalysts, but near the end of the second year of operation (operating under a research permit), the CO emission levels began to rise. The emission levels got to just above 100 ppmv before the catalyst was removed from service and samples were sent for testing (average outlet CO ppm level was 7.5 ppmv during the pilot study). The results confirmed that there was some

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deactivation of the catalyst evidenced by the presence of a variety of contaminants suspected to originate from the operation of the engine. Although there was an elevation in the CO emissions, this cannot constitute a catalyst failure since the outlet CO emissions were still in compliance with the proposed CO limit of 250 ppm before removed from service. The oxidation catalysts at Ox Mountain have experienced something similar and yet have been achieving compliance with Staff's proposed CO limit for almost three years. Despite this, a catalyst replacement interval of two years, instead of three years, has been applied as part of the cost analysis described in further detail below.

Emissions and emission reductions are calculated for NOx, VOC, and CO. The current emissions are calculated from the current Rule 1110.2 rule limits and permit limits, while the future emissions are calculated from the proposed Rule 1110.2 limits. Permit limits were used for some engines because they were permitted at BACT or have more stringent permit limits than in the current rule. For calculating cost effectiveness, the AQMD uses the Discounted Cash Flow (DCF) model, which takes into consideration both capital cost plus annual operating and maintenance costs. This use of this model is consistent with previous rulemaking proposals and past control measures because it links the cost of the project with its environmental benefits. The equipment is given a twenty year life and a 4% interest rate. The calculated present worth value (PWV) is then divided by the summation of the emission reductions over the length of the project (20 years). The emission reductions for CO are discounted by one seventh because of its ozone-formation potential is approximately one seventh from that of NOx.

The 2008 Interim Technology Assessment provided preliminary cost information for a non-regenerative siloxane removal system with oxidation catalyst and SCR, based on OCSD's pilot study cost estimates as the project was beginning. Table 6 provides a comparison between the cost estimates from the Interim Report and those obtained from OCSD's Final Report on its pilot study. The emission reductions in the Interim Report did not include those from CO and assumed an annual operation of 8,000 hours. This explains the difference in the cost effectiveness between the Interim Report and OCSD's final report.

Table 6. Comparison of OCSD's Costs for Pilot Study Installation and Operation

	Interim Report	Final Report
Installed Equipment, $	1,265,000	1,989,529
Equipment minus Catalyst, $	*1,096,000*	*1,875,129*
Catalyst Cost, $	*169,000*	*114,400*
Project Management & Installation Supervision, $	285,000	298,429
Total Initial Investment, $	**1,550,000**	**2,287,958**
Sorbent Replacement, $/yr	62,000	40,000
Catalyst Replacement, $/yr (3 year replacement)	56,000	38,133
Reactant, $/yr	15,238	18,900
Reduced Power Production, $/yr	2,363	1,200
Equipment Maintenance, $/yr	-7,440	-30,147
Total Annual Cost, $	**128,161**	**58,950**
Present Value of 20-yr Cost, $	**3,360,916**	**3,089,089**
NOx Reductions	15.18	10.7
VOC Reductions	2.20	14.6
CO Reductions	0	64.9
Cost Effectiveness ($/ton NOx+VOC+CO/7)	**11,100**	**4,500***
$/kW-hr	**0.08**	**0.01**

*This figure is based on permit-specific limits that are lower than the current Rule 1110.2 limits and on 6,000 annual operating hours.

The actual capital costs were higher than was estimated in the Interim Report, but the operation and maintenance costs were actually lower due to the reduced engine maintenance and emission fee credits from the lower emissions. The calculated cost effectiveness of OCSD's 3471 bhp engine and based on the Final Report is $4,500 per ton of NOx, VOC, and CO/7. OCSD's permit limits for its demonstration project engine are 45ppmv NOx, 209 ppmv VOC, and 590 ppmv CO. Some facilities such as OCSD use the efficiency correction factor (ECF) to operate at a slightly higher NOx and/or VOC limit, for example.

The installation and operating costs for OCSD's system were scaled across a series of varying digester gas engine sizes representative of the current population. OCSD's cost effectiveness was calculated based on 6,000 annual operating hours for the pilot study. The cost effectiveness for this analysis is based on 8,000 operating hours. 8,000 hours was used as a typical usage level for the engines analyzed for the Interim Report. Emissions reductions are calculated from the current Rule 1110.2 rule and permit limits to the proposed Rule 1110.2 limits. Table 7 summarizes these results for digester gas at the base level. The base level assumes a catalyst replacement every two years and the

sorbent costs from the pilot study. The cost effectiveness range for digester gas is between $1,700 and $3,500 per ton of NOx, VOC, and CO/7.

Table 7. Base Level Cost Effectiveness for Digester Gas Engines Based on OCSD's Actual Costs

BHP	4200	3471	1600	1000	500	250
Installed Equipment, $	**2,240,791**	**1,989,529**	**1,230,965**	**921,665**	**602,807**	**395,072**
Equipment minus Catalyst, $	2,102,364	1,875,129	1,178,231	888,707	586,328	386,832
Catalyst Cost, $	138,427	114,400	52,734	32,959	16,479	8,240
Project Management & Installation Supervision, $	361,107	298,429	137,565	85,978	42,989	21,494
Total Initial Investment, $	**2,601,898**	**2,287,958**	**1,368,529**	**1,007,643**	**645,796**	**416,566**
Sorbent Replacement, $/yr	48,401	40,000	18,438	11,524	5,762	2,881
Catalyst Replacement, $/yr (every 2 yr)	69,213	57,200	26,367	16,479	8,240	4,120
Reactant, $/yr	22,869	18,900	8,712	5,445	2,723	1,361
Reduced Power Production, $/yr	2,859	1,200	1,089	681	340	170
Equipment Maintenance, $/yr	-36,479	-30,147	-13,897	-8,685	-4,343	-2,171
Total Annual Cost, $	**106,865**	**87,153**	**40,710**	**25,444**	**12,722**	**6,361**
Present Value of 20-yr Cost, $	**4,054,188**	**3,472,367**	**1,921,783**	**1,353,427**	**818,688**	**503,012**
NOx Reduction, tpy	12.6	10.5	4.8	3	1.5	1
VOC Reduction, tpy	29	24	11.1	6.9	3.5	1.7
CO Reduction, tpy	538.9	445.4	205.3	128.3	64.2	32.1
CO Reduction/7, tpy	77.0	63.6	29.3	18.3	9.2	4.6
Cost Effectiveness, $ per ton of						
NOx+VOC+CO/7	**1700**	**1800**	**2100**	**2400**	**2900**	**3500**
$/kW-hr	**0.008**	**0.009**	**0.010**	**0.012**	**0.014**	**0.017**

OCSD's actual equipment costs (gas cleanup, oxidation catalyst, SCR, platform) and operating costs (with catalyst change outs every two years) were also applied to landfill gas engines to determine their cost effectiveness. The equipment costs were increased to account for the higher inlet gas volume per BTU supplied to the engine. The cost effectiveness range for landfill gas is between $2,300 and $2,900 per ton of NOx, VOC, and CO/7. The base level cost effectiveness for this analysis is based on 8,000 operating hours and is summarized in Table 8.

Table 8. Base Level Cost Effectiveness for Landfill Gas Engines Based on OCSD's Actual Costs

BHP	4200	3471	2700	2000	1500
Installed Equipment, $	**2,345,061**	**2,082,529**	**1,781,763**	**1,479,753**	**1,239,133**
Equipment minus Catalyst, $	*2,206,634*	*1,968,129*	*1,692,774*	*1,413,835*	*1,189,695*
Catalyst Cost, $	*138,427*	*114,400*	*88,989*	*65,918*	*49,438*
Project Management & Installation Supervision, $	*361,107*	*298,429*	*232,140*	*171,956*	*128,967*
Total Initial Investment, $	**2,706,168**	**2,380,958**	**2,013,903**	**1,651,708**	**1,368,100**
Sorbent Replacement, $/yr	48,401	40,000	31,115	23,048	17,286
Catalyst Replacement, $/yr (every 2 yr)	69,213	57,200	44,494	32,959	24,719
Reactant, $/yr	22,869	18,900	14,702	10,890	8,168
Reduced Power Production, $/yr	1,664	1,200	1,069	792	594
Equipment Maintenance, $/yr	-36,479	-30,147	-23,451	-17,371	-13,028
Total Annual Cost, $	**105,669**	**87,153**	**67,930**	**50,319**	**37,739**
Present Value of 20-yr Cost, $	**4,142,210**	**3,565,367**	**2,937,073**	**2,335,538**	**1,880,972**
NOx Reduction, tpy	**12.6**	**10.5**	**8.1**	**6**	**4.5**
VOC Reduction, tpy	**1.3**	**1.1**	**0.8**	**0.6**	**0.5**
CO Reduction, tpy	538.9	445.4	346.4	256.6	192.5
CO Reduction/7, tpy	77.0	63.6	49.5	36.7	27.5
Cost Effectiveness, $ per ton of NOx+VOC+CO/7	**2300**	**2400**	**2500**	**2700**	**2900**
$/kW-hr	**0.009**	**0.009**	**0.009**	**0.010**	**0.011**

*The equipment costs were increased by $93,000 to account for the siloxane cleanup system's processing of a greater gas volume per BTU supplied to the engine

Several stakeholders have expressed concern over the high cost of gas cleanup, primarily to address the removal of siloxanes from the biogas inlet stream. In addition, all facilities have varying levels of impurities in the biogas and some may have to install additional pretreatment for sulfur compounds if the levels are high. Redundant siloxane removal systems are a necessity and must be capable of handing the base siloxane load as well as intermittent spikes. To address these concerns in the cost analysis, Staff analyzed two other scenarios where additional gas treatment contingencies were added to the operational costs. These costs are based on vendor quotes for the full scale of flow rates of all the affected biogas facilities. The media costs were then normalized to obtain "per engine" costs, which were then bracketed to the appropriate engine brake horsepower sizes. The carbon media change-out frequency is dependent on the siloxane level; the higher the siloxane level, the more frequent the media change-out. The cost of the media

is correlated to the media weight relative to the flow rate and vessel size. Staff has assumed a worst case where media change-outs will be required once per month.

On top of this, Staff also included a 20% contingency to the equipment costs to account for any additional gas cleanup required or to account for backpressure considerations in smaller engines or for additional compression and chilling equipment. Vendor supplied equipment costs are in line with the scaled costs from the base scenario for both gas cleanup and catalytic after-treatment. The operating costs are the major contributor to the overall cost of the gas cleanup system. The following two tables (Tables 9 and 10) represent the worst case costs with the additional gas cleanup and the additional 20% equipment cost contingency applied.

Table 9. Cost Effectiveness for Digester Gas Engines Based on OCSD's Actual Costs with Additional Contingencies

| BHP	4200	3471	1600	1000	500	250
Installed Equipment, $	2,240,791	1,989,529	1,230,965	921,665	602,807	395,072
Equipment minus Catalyst, $	2,102,364	1,875,129	1,178,231	888,707	586,328	386,832
Added Cleanup w/20% contingency	420,473	375,026	235,646	177,741	117,266	77,366
Catalyst Cost, $	138,427	114,400	52,734	32,959	16,479	8,240
Installed Equipment w/20% contingency, $	**2,661,264**	**2,364,555**	**1,466,611**	**1,099,407**	**720,073**	**472,438**
Project Management & Installation Supervision, $	361,107	298,429	137,565	85,978	42,989	21,494
Total Initial Investment, $	**3,022,371**	**2,662,984**	**1,604,176**	**1,185,384**	**763,062**	**493,933**
Sorbent Replacement, $/yr	165,600	138,000	69,000	103,500	51,570	12,420
Catalyst Replacement, $/yr (every 2yr)	69,213	57,200	26,367	16,479	8,240	4,120
Reactant, $/yr	22,869	18,900	8,712	5,445	2,723	1,361
Reduced Power Production, $/yr	2,859	1,200	1,089	681	340	170
Equipment Maintenance, $/yr	-36,479	-30,147	-13,897	-8,685	-4,343	-2,171
Total Annual Cost, $	**224,064**	**185,153**	**91,272**	**117,420**	**58,530**	**15,900**
Present Value of 20-yr Cost, $	**6,067,395**	**5,179,213**	**2,844,560**	**2,781,121**	**1,558,484**	**710,013**
NOx Reduction, tpy	12.6	10.5	4.8	3	1.5	1
VOC Reduction, tpy	29	24	11.1	6.9	3.5	1.7
CO Reduction, tpy	538.9	445.4	205.3	128.3	64.2	32.1
CO Reduction/7, tpy	77.0	63.6	29.3	18.3	9.2	4.6
Cost Effectiveness, $ per ton of NOx+VOC+CO/7	**2600**	**2600**	**3100**	**4900**	**5500**	**4900**
$/kW-hr	**0.012**	**0.013**	**0.015**	**0.024**	**0.027**	**0.025**

Table 10. Cost Effectiveness for Landfill Gas Engines Based on OCSD's Actual Costs with Additional Contingencies

BHP	4200	3471	2700	2000	1500
Installed Equipment, $	2,345,061	2,082,529	1,781,763	1,479,753	1,239,133
Equipment minus Catalyst, $	2,206,634	1,968,129	1,692,774	1,413,835	1,189,695
Added Cleanup w/20% contingency	441,327	393,626	338,555	282,767	237,939
Catalyst Cost, $	138,427	114,400	88,989	65,918	49,438
Installed Equipment w/20% contingency, $	**2,786,388**	**2,476,155**	**2,120,318**	**1,762,520**	**1,477,072**
Project Management & Installation Supervision, $	361,107	298,429	232,140	171,956	128,967
Total Initial Investment, $	**3,147,495**	**2,774,584**	**2,352,458**	**1,934,475**	**1,606,039**
Sorbent Replacement, $/yr	276,000	276,000	138,000	207,000	103,500
Catalyst Replacement, $/yr (every 2yr)	69,213	57,200	44,494	32,959	24,719
Reactant, $/yr	22,869	18,900	14,702	10,890	8,168
Reduced Power Production, $/yr	1,664	1,200	1,069	792	594
Equipment Maintenance, $/yr	-36,479	-30,147	-23,451	-17,371	-13,028
Total Annual Cost, $	**333,268**	**323,153**	**174,815**	**234,270**	**123,953**
Present Value of 20-yr Cost, $	**7,676,607**	**7,166,233**	**4,728,196**	**5,118,211**	**3,290,558**
NOx Reduction, tpy	12.6	10.5	8.1	6	4.5
VOC Reduction, tpy	1.3	1.1	0.8	0.6	0.5
CO Reduction, tpy	538.9	445.4	346.4	256.6	192.5
CO Reduction/7, tpy	77.0	63.6	49.5	36.7	27.5
Cost Effectiveness, $ per ton of NOx+VOC+CO/7	**4200**	**4800**	**4000**	**5900**	**5100**
$/kW-hr	**0.016**	**0.018**	**0.015**	**0.022**	**0.019**

The worst case costs, along with the base case costs were plotted on the following two graphs for digester gas and landfill gas (Figure 7 and Figure 8). Since every facility is unique in the flow rate, engine size, and number of engines installed, the bracketed sorbent replacement costs are not necessarily linear. However, there is a sufficient correlation to apply a polynomial regression to each curve (with additional gas cleanup and with 20% additional contingency) and be able to represent them here. The worst case scenario cost effectiveness range for digester gas is from $2,600 to $5,500 per ton and from $4,200 to $5,900 per ton for landfills.
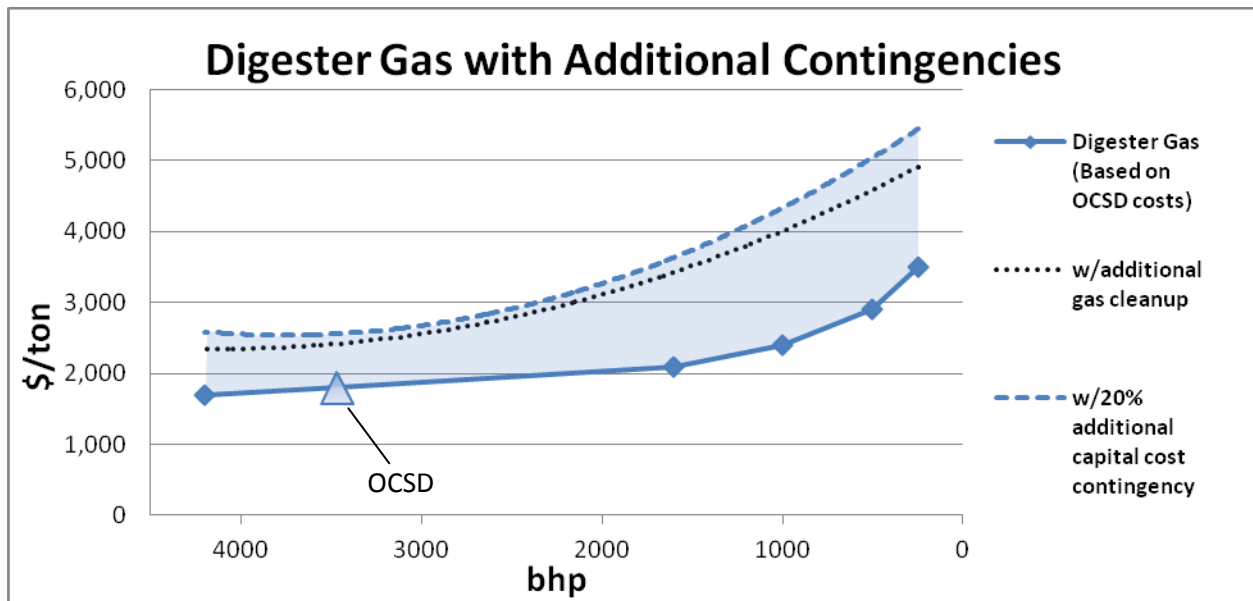
Figure 7. Cost Effectiveness for Digester Gas (Catalytic Aftertreatment)
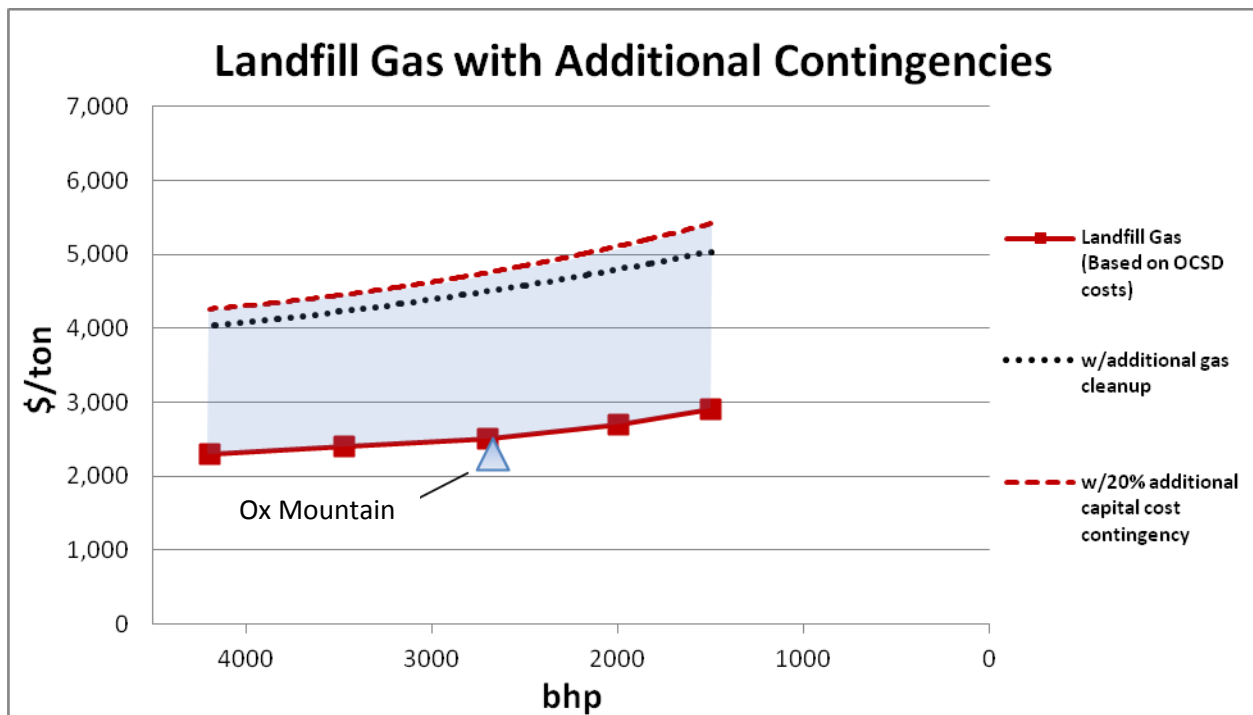
Figure 8. Cost Effectiveness for Landfill Gas (Catalytic Aftertreatment)

Cost data was also received from the Bay Area AQMD for the installation at Ox Mountain Landfill's 2,677 bhp engine with regenerative temperature swing adsorption (TSA) gas cleanup, oxidation catalyst, and SCR (Table 9). There are six total engines at that facility.   Cost effectiveness was calculated from SCAQMD rule limits to the proposed rule limits, operating 8,000 hours per year. There may be an increased capital cost for a regenerative TSA system, but the total gas cleanup cost was divided by 6 to arrive at the per-engine estimate. The cost effectiveness for Ox Mountain is within the range of Staff's estimates for the proposed amendments (Figure 8). The annual costs presented here do not reflect any credit taken for reduced engine maintenance, so the actual operating costs may be lower than those in Table 11. From Ox Mountain's experience, the sorbent change-outs could be longer than once every twelve months.

Table 11. Cost Effectiveness of Landfill Installation with Regenerative Gas Cleanup, Oxidation Catalyst, and SCR

Capital Costs*	
TSA System, $	271,544
TSA Installation, $	91,480
TSA Flare, $	25,105
TSA Flare Install, $	6,699
SCR System, $	46,218
SCR Install, $	28,960
Ox Cat System, $	38,218
Ox Cat Install, $	28,377
CEMS, $	170,165
CEMS Install, $	20,080
Design & Eng (3.4% of equip), $	18,742
Const & Comm (8% of equip), $	44,100
Total Installed Cost, $	**789,688**
Operating Costs	
TSA, $	14,000
Flare, $	2,917
CEMS, $	34,600
SCR, $	51,394
Ox Cat, $	12,514
Labor, $	10,000
Electricity, $	8,790
Total Annual Op Costs, $	**134,215**
PWV (20 yrs @4%), $	**2,613,673**
NOx Reduction, tpy	8.1
VOC Reduction, tpy	0.8
CO Reduction, tpy	343.5
CO Reduction/7, tpy	49.1
Cost Effectiveness, $ per ton of	
NOx+VOC+CO/7	**2,300**
$/kW-hr	**0.008**

*TSA system costs were divided by 6 to reflect a per-engine basis estimate

NOxTech Cost Effectiveness

Cost information was also obtained from NOxTech based on its installation at Eastern Municipal Water District's (EMWD) Mills Station. EMWD also submitted cost data

reflecting the additional costs to install an EGR unit as it is currently undergoing further testing for its demonstration. For the cost effectiveness analysis, EMWD's additional costs amounted to a contingency for the installation costs of the NOxTech unit with EGR and its associated equipment. The addition of an EGR system is not anticipated to be required on landfill gas installations, so the contingency will be applied only to digester gas engines. The total amounts of contingency cost experienced by EMWD are not expected to be incurred by subsequent users. Table 11 shows the base level based on costs submitted by NOxTech for digester gas engines, while Table 12 shows the additional contingencies. Table 13 shows the base level only for landfill gas engines.

Table 11. Base Level Cost Effectiveness for Digester Gas Engines Based on NOxTech Costs

BHP	4200	3471	1600	1350	1000	500	250
Installed Equipment, $							
Equipment Cost, $	960,000	800,000	400,000	400,000	400,000	400,000	400,000
Installation Cost, $	250,000	200,000	100,000	100,000	100,000	100,000	100,000
Project Management & Installation Supervision, $	31,742	26,452	13,226	13,226	13,226	13,226	13,226
Total Initial Investment, $	**1,241,742**	**1,026,452**	**513,226**	**513,226**	**513,226**	**513,226**	**513,226**
Reactant, $/yr	37,952	31,365	14,458	12,199	9,036	4,518	2,259
Reduced Power Production, $/yr	68,365	56,499	26,044	21,975	16,277	8,139	4,069
Equipment Maintenance, $/yr	16,000	16,000	8,100	8,100	8,100	8,100	8,100
Total Annual Cost, $	**122,318**	**103,864**	**48,602**	**42,274**	**33,414**	**20,757**	**14,428**
Present Value of 20-yr Cost, $	**2,904,042**	**2,437,965**	**1,173,728**	**1,087,724**	**967,319**	**795,312**	**709,308**
NOx Reduction, tpy	12.6	10.5	4.8	4.1	3	1.5	1
VOC Reduction, tpy	29	24	11.1	9.3	6.9	3.5	1.7
CO Reduction, tpy	538.9	445.4	205.3	173.2	128.3	64.2	32.1
CO Reduction/7, tpy	77.0	63.6	29.3	24.7	18.3	9.2	4.6
Cost Effectiveness, $ per ton of NOx+VOC+CO/7	**1200**	**1200**	**1300**	**1400**	**1700**	**2800**	**4900**
$/kW-hr	**0.006**	**0.006**	**0.006**	**0.007**	**0.008**	**0.014**	**0.025**

Table 12. Cost Effectiveness for Digester Gas Engines Based on EMWD's Costs with Additional Contingencies

BHP	4200	3471	1600	1350	1000	500	250
Installed Equipment, $							
Equipment Cost, $	960,000	800,000	400,000	400,000	400,000	400,000	400,000
Installation Cost, $	250,000	200,000	100,000	100,000	100,000	100,000	100,000
Installation Cost Contingency, $	300,000	300,000	300,000	300,000	300,000	300,000	300,000
Project Management & Installation Supervision, $	31,742	26,452	13,226	13,226	13,226	13,226	13,226
Total Initial Investment, $	**1,541,742**	**1,326,452**	**813,226**	**813,226**	**813,226**	**813,226**	**813,226**
Reactant, $/yr	37,952	31,365	14,458	12,199	9,036	4,518	2,259
Reduced Power Production, $/yr	68,365	56,499	26,044	21,975	16,277	8,139	4,069
Equipment Maintenance, $/yr	16,000	16,000	8,100	8,100	8,100	8,100	8,100
Total Annual Cost, $	**122,318**	**103,864**	**48,602**	**42,274**	**33,414**	**20,757**	**14,428**
Present Value of 20-yr Cost, $	**3,204,042**	**2,737,965**	**1,473,728**	**1,387,724**	**1,267,319**	**1,095,312**	**1,009,308**
NOx Reduction, tpy	12.6	10.5	4.8	4.1	3	1.5	1
VOC Reduction, tpy	29	24	11.1	9.3	6.9	3.5	1.7
CO Reduction, tpy	538.9	445.4	205.3	173.2	128.3	64.2	32.1
CO Reduction/7, tpy	77.0	63.6	29.3	24.7	18.3	9.2	4.6
Cost Effectiveness, $ per ton of							
NOx+VOC+CO/7	**1400**	**1400**	**1600**	**1800**	**2200**	**3900**	**6900**
$/kW-hr	**0.007**	**0.007**	**0.008**	**0.009**	**0.011**	**0.019**	**0.035**

Table 13. Base Level Cost Effectiveness for Landfill Gas Engines Based on NOxTech Costs

BHP	4200	3471	2700	2000	1500	1350
Installed Equipment, $						
Equipment Cost, $	*960,000*	*800,000*	*800,000*	*400,000*	*400,000*	*400,000*
Installation Cost, $	*250,000*	*200,000*	*200,000*	*100,000*	*100,000*	*100,000*
Project Management & Installation Supervision, $	31,742	26,452	26,452	13,226	13,226	13,226
Total Initial Investment, $	**1,241,742**	**1,026,452**	**1,026,452**	**513,226**	**513,226**	**513,226**
Reactant, $/yr	37,952	31,365	24,398	18,073	13,554	12,199
Reduced Power Production, $/yr	53,041	43,834	34,098	25,258	18,943	17,049
Equipment Maintenance, $/yr	16,000	16,000	16,000	8,100	8,100	8,100
Total Annual Cost, $	**106,993**	**91,199**	**74,496**	**51,430**	**40,598**	**37,348**
Present Value of 20-yr Cost, $	**2,695,780**	**2,265,852**	**2,038,847**	**1,212,161**	**1,064,947**	**1,020,783**
NOx Reduction, tpy	12.6	10.5	8.1	6	4.5	4.1
VOC Reduction, tpy	1.3	1.1	0.8	0.6	0.5	0.4
CO Reduction, tpy	538.9	445.4	346.4	256.6	192.5	173.2
CO Reduction/7, tpy	77.0	63.6	49.5	36.7	27.5	24.7
Cost Effectiveness, $ per ton of						
NOx+VOC+CO/7	**1500**	**1500**	**1700**	**1400**	**1600**	**1700**
$/kW-hr	**0.006**	**0.006**	**0.007**	**0.005**	**0.006**	**0.007**

Figures 9 and 10 illustrate the cost effectiveness for NOxTech graphically. For digester gas, the shaded band reflects the possible contingency costs in relation to the base level costs. For landfills, the modular nature of the base level equipment costs from NOxTech result in a slightly less than linear representation. However, there is sufficient correlation to apply a regression that results in the curve illustrated in Figure 10.
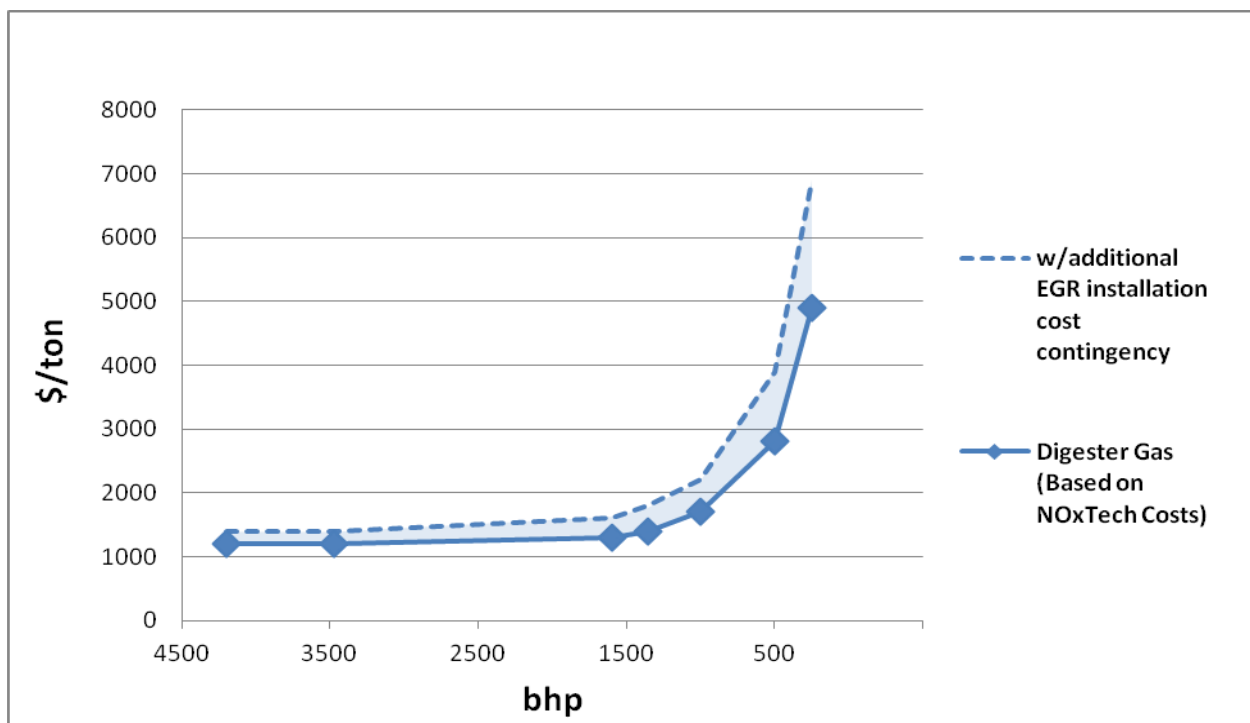
Figure 9. Cost Effectiveness for Digester Gas Based on NOxTech Costs with Additional Contingencies
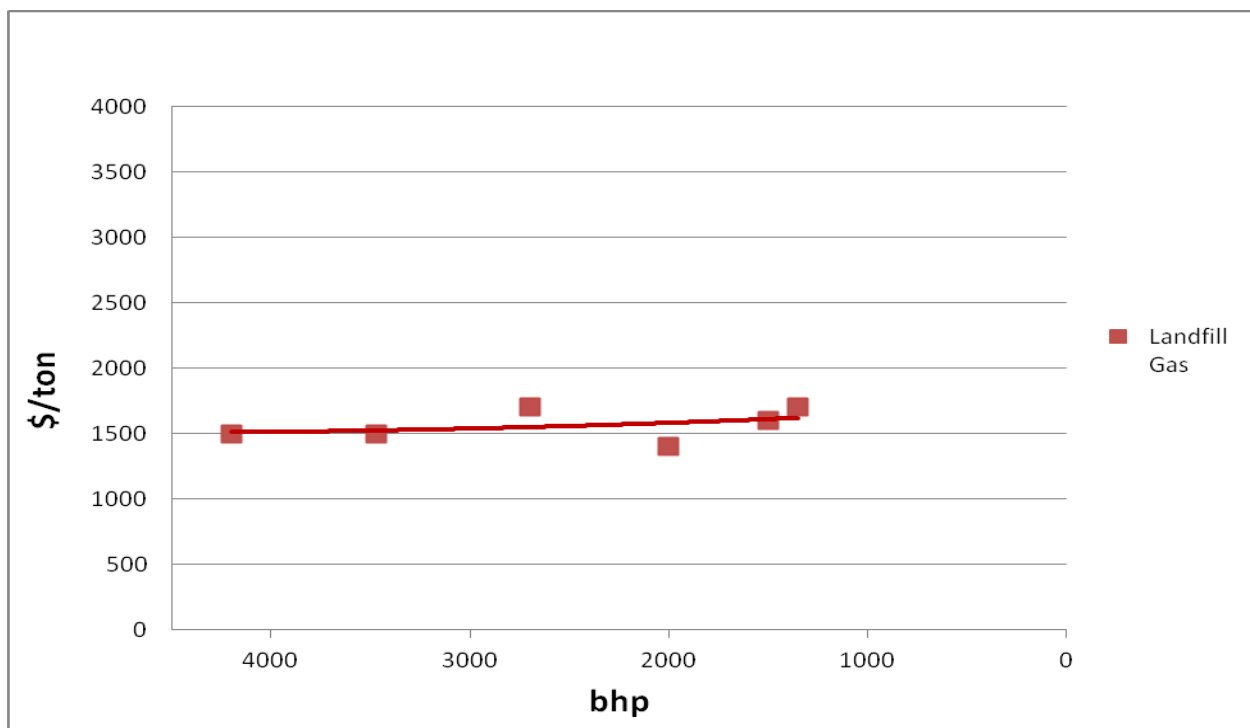
Figure 10. Cost Effectiveness for Landfill Gas Based on NOxTech Costs

The cost effectiveness estimates presented here are within the range of cost effectiveness estimates presented to the Governing Board for past rulemakings. Digester gas and landfill gas engines of all sizes are shown to be cost-effective for all scenarios. The dollars per kilowatt-hour estimates (which assume a 97% generator efficiency) also show that the addition of emission controls is cheaper than the cost of electricity from the grid which runs about 8 to 10 cents per kilowatt-hour.

GLOBAL WARMING IMPACTS

The Adopting Board Resolution for the February 1, 2008 amendment of Rule 1110.2 directed AQMD staff to prepare a Technology Assessment including a summary of potential trade-offs between greenhouse gas (GHG) and criteria pollutant emissions due to the adoption of the proposed biogas emission limits (NOx limit of 11 ppm (referenced to 15% O_2), VOC limit of 30 ppm and CO limit of 250 ppm). Operation of the IC engines using biogas to produce electrical power generates the three criteria pollutants NOx, VOC and CO. If the operators of those engines elect to cease power generation then the biogas must be flared or redirected to another usage onsite including fueling boilers. The choice to generate power or not leads to a trade-off: upgrade the power generation emissions controls to obtain a cleaner emissions profile or potentially shutdown the internal power generation and flare but in doing so release more greenhouse gases. The following discussion provides a comparison of the impacts the two options present: criteria pollutant emissions and greenhouse gas emissions from operation of the IC engines vs. flaring.

Criteria Pollutant Impact

Figures 11 through 13 compare emissions of criteria pollutants from existing engines, an engine meeting the proposed limits and biogas flares at facilities affected by the proposed biogas emission limits. The range of flare emissions shown in the following figures represents the variety of permit limits and operating conditions for flares at affected facilities. The permit emissions limits vary because the age of flares at these facilities ranges from less than 10 years to 40 years old. The emissions for each technology include the direct emissions from fuel combustion (natural gas). The flare emissions also include the criteria emissions from local utility power plants when biogas is directed to flares instead of being used to generate electricity using IC engines.

The NOx, VOC and CO emissions comparisons depicted in Figures 11 through 13 are expressed as a percent compared to the proposed engine emission limits – a ratio of the

current and proposed emission limits in ppm or pounds of emissions per Btu of fuel consumed. In addition, Figures 11 and 12 show the range of the current NOx and VOC emission limits for large and small engines. Also included in the three figures are the estimates of flare emissions and the emissions from a large power plant. These emissions are included because when an engine is shut down, the replacement electricity is assumed to be generated by a local utility boiler or combined cycle turbine.

The comparison of criteria pollutant emissions from engines and flares uses the ratio of the emission limit for the specific technology to the emission factor for an engine meeting the proposed biogas emission limits (NOx limit of 11 ppm (referenced to 15% O_2), VOC limit of 30 ppm and CO limit of 250 ppm). This ratio is then converted to percent with the proposed engine limit set at 100%. This ratio can be generated by converting all emission limits to parts per million at 15% O_2 (the reference level for the Rule 1110.2 emission limits) or by converting all emission limits to pounds per million Btu.

The emission comparisons assume that the biogas is diverted to flares from engines and there is an equivalent amount of electricity produced by local power plants meeting current BACT. Compared to flares, power plant criteria pollutant emissions are smaller because limits are very low and base load power plants use one-half of the fuel of engines to produce the same amount of electricity. These emissions are included in Figures 11 to 13 as part of the flare emissions. While there are other sources of electricity outside the AQMD, the amount of electricity produced by biogas engines is small in comparison and local base load power plants have enough capacity to replace these sources at a cost-effective price.

As presented in the Figures 11 through 13, the option to flare emissions would generate less criteria pollutant emissions than are currently produced under the existing emissions limits, regardless of flare configuration. Operating the IC engines at the proposed limits would be cleaner for NOx and VOC than venting emissions to the Pre-1998 flares (which include the required base load emissions). In each case, flaring using a BACT flare, including the base load emissions would generate fewer emissions than for IC engines operating within the proposed new emissions limits. However, the option to flare raises illuminates the counterpoint argument: Does flaring result in a greater GHG emissions impact than generating internal power?
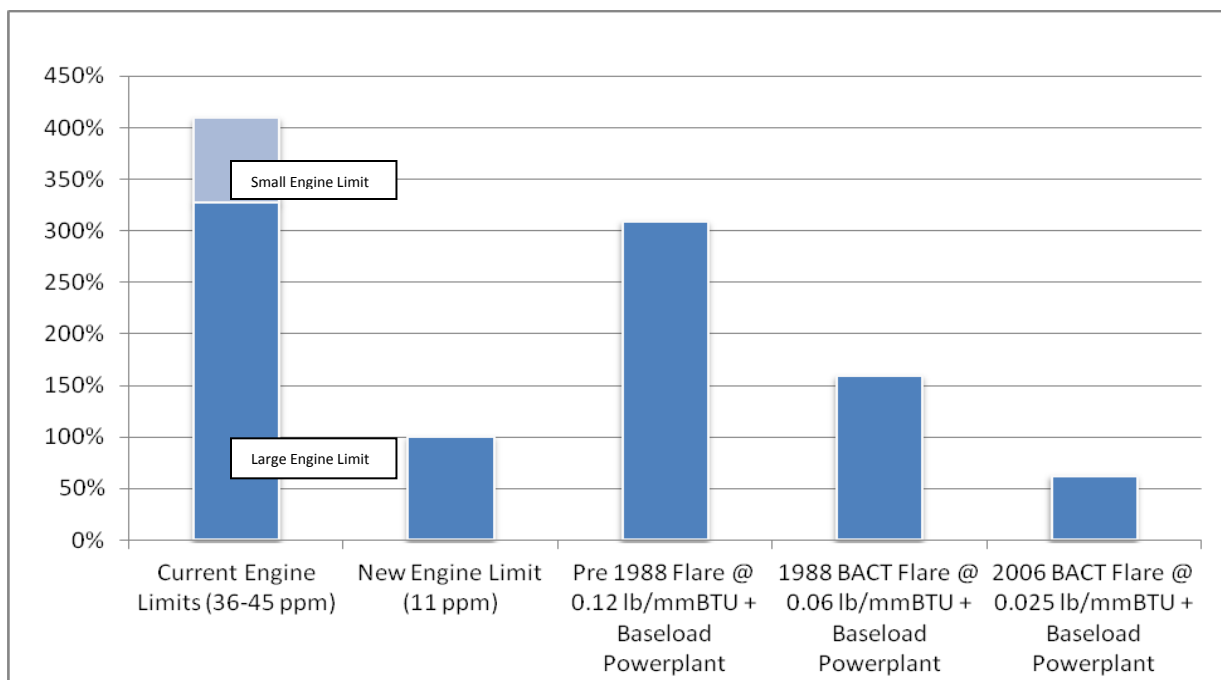
Figure 11

Biogas Flare and Engine NOx Emissions Compared to an 11 PPM Emissions Limit
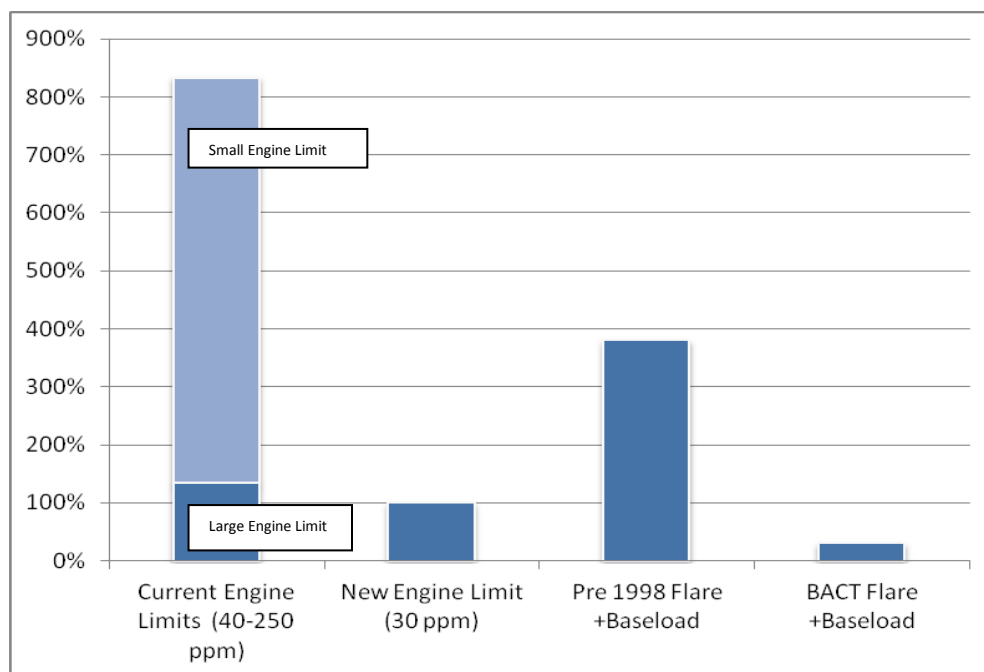
Figure 12

Biogas Flare and Engine VOC Emissions Compared to a 30 PPM Emissions Limit
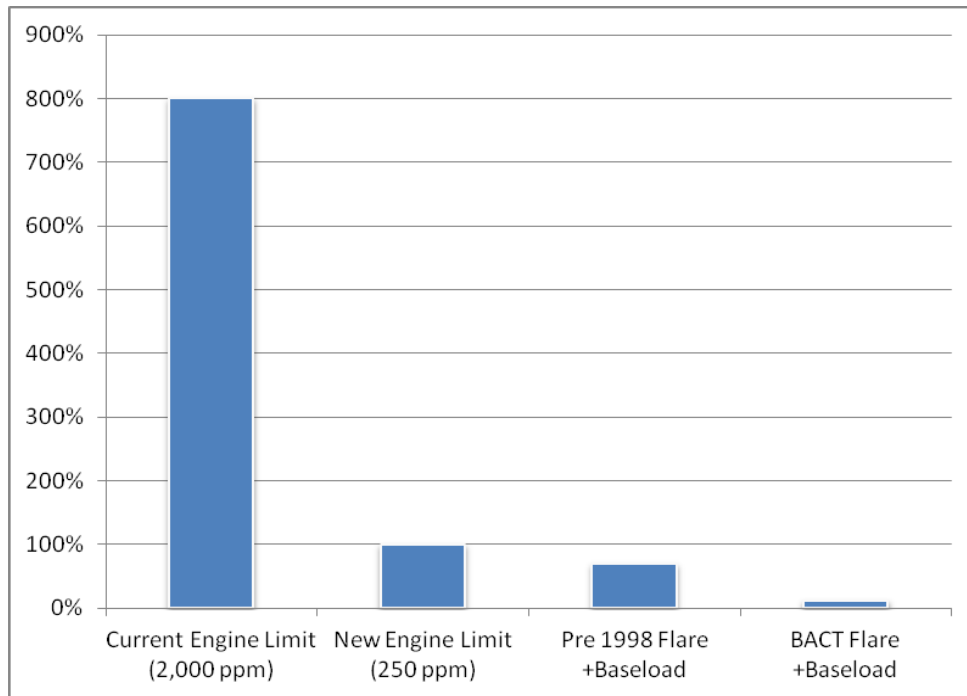
Figure 13

Biogas Flare and Engine CO Emissions Compared to a 250 PPM Emissions Limit

Greenhouse Gas Impacts

Figure 14 provides a comparison of greenhouse gas emissions impact from engines, flares and base load power generation. The figure includes emissions from engines using different amounts of supplemental fuel (natural gas), power plants and newer versus older flare technologies. The differences in GHG emissions are expressed as percent compared to biogas engine emissions. The GHG emission comparison in Figure 14 is based on carbon dioxide equivalents (CO_2e). Emissions of gases that contribute to global warming are represented as CO_2 equivalents by taking into account their warming potential in the atmosphere relative to CO_2. For example, methane (CH_4) is assigned a warming potential of 21 times CO_2 (over a 100 year timeframe).

More specifically, the comparison of GHG emissions is also a ratio of each technologies emissions (expressed as carbon dioxide equivalents – CO_2e) to the CO_2e associated with an IC engine using 15% supplemental natural gas. This ratio is developed on a mass basis. In the case of an IC engine and pre-2006 flare, it is assumed that for every 100 methane molecules provided as fuel to the engine, 99 are combusted to CO_2 and one is emitted in the exhaust. The global warming potential of this one methane molecule is

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equivalent to 21 CO_2 molecules. In addition, 15% of the fuel methane for the base engine and pre-2006 flare scenarios comes from natural gas. The 2010 U.S. EPA method for estimating the CO_2e GHG emissions related from natural gas production and transport to an average of about 20% of the fuel Btu delivered to an operation. In 2011, EPA revised its estimate upwards to average of about 35% of the fuel Btu delivered. Using the 2011 U.S. EPA percentage translates to an additional CO_2e of 6 more molecules of CO_2 due to production and transport of that natural gas. The summation of these emissions in terms of CO_2 equivalence results in an impact of 126 CO_2 molecules for every 100 molecules of methane provided to the engine.

The same methodology is used to generate the CO_2e emissions from an engine using 50% supplemental natural gas with the same Btu content, a flare meeting current BACT limits and a base load power plant generating the same amount of electricity as the IC engine (using ½ the Btu of an engine). A flare meeting 2006 BACT has more complete combustion and emits half of the methane than older flares emit and does not require supplemental natural gas. These "emissions" are then used to generate a ratio with the base engine represented as 100%. In this analysis, the electricity is produced by local power plants in order to determine the worst case emissions if engines are replaced with flares.

As depicted in Figure 14, operation of the IC engine using a 15 percent natural gas and 85 percent biogas is equivalent to 126 CO_2 molecules or a factor of 1.0 on the chart. An engine burning 50 percent natural gas has a higher ratio because of the additional production and transport contribution to the total CO_2e. Using a Pre 2006 (non-BACT) flare with the 15 percent natural gas contribution has an equivalent CO_2e signature as the biogas engine (1.0). The BACT flare and base load power generation (with the production and transport contribution to the total CO_2e) exhibit lower GHG impacts compared to the biogas engine or the Pre 2006 flare. However, if a facility elects to flare the gas with a Pre 2006 flare but acquires power from the grid, the factor approaches 1.8 or 80 percent more GHG emissions than continued operation of the IC engine. Even if a facility uses a BACT flare but needs supplemental power from the grid, the factor rises to approximately 1.5 or 50 percent GHG emissions above the continued operation of the IC engine.
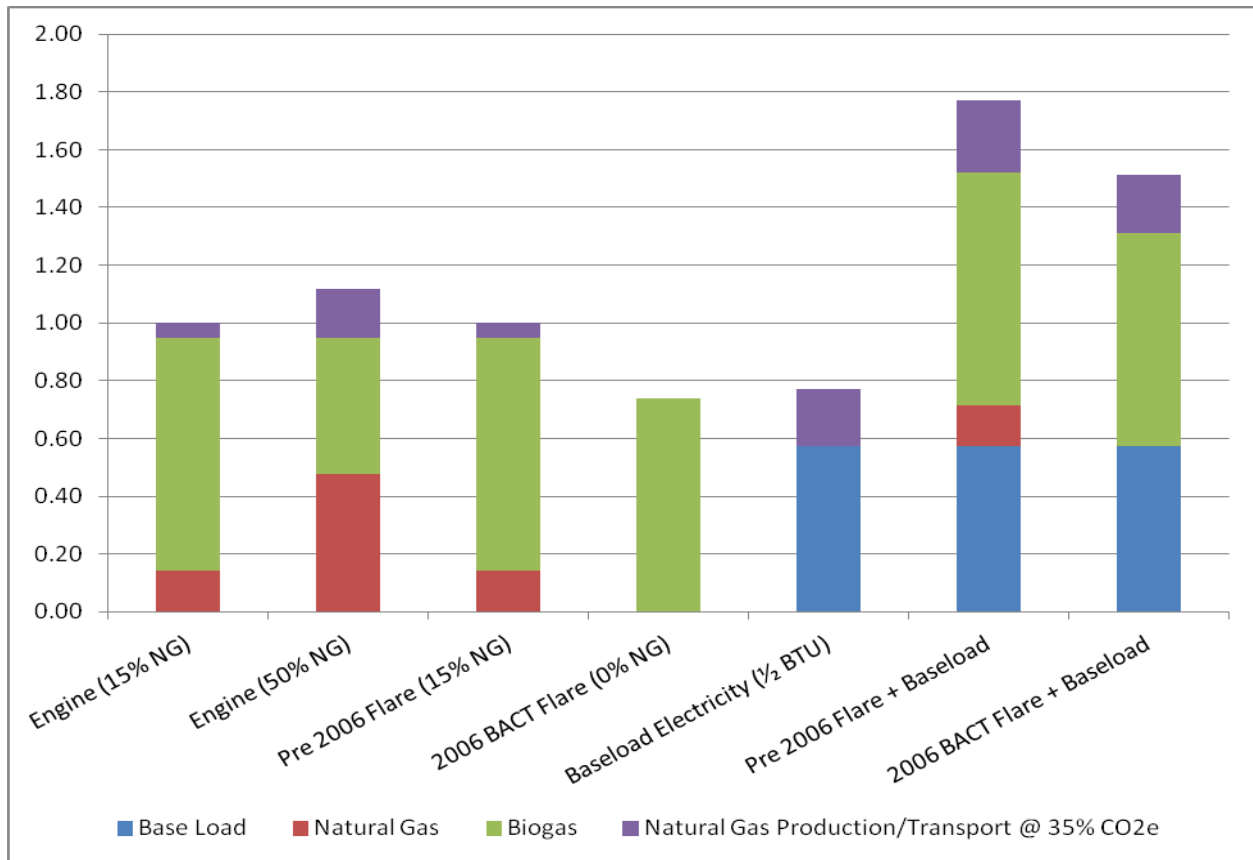
Figure 14

Comparison of CO$_2$ Equivalent Greenhouse Emissions from Flares and Base Load Electricity and IC Engines

GHG Impact Summary

The above analysis provides background assessments of the trade-off between achieving lower criteria pollutant emissions levels from complying with the proposed new standards and the possible GHG emissions penalty which may be incurred if a facility flares but is required to purchase power from the grid. Compared to current biogas engines, flares typically have lower criteria pollutant emissions profiles but have higher emissions of greenhouse gases because electricity must be generated by other sources if the biogas is not used in an engine generating electricity (Table 14).

Table 14. Comparison of Criteria Pollutant and GHG Impacts from ICE Operating and from Flaring

Pollutant	Magnitude of Flaring w/BACT Flare + Baseload Compared to ICEs
NOx	5 to 7x Less
CO	67x Less
VOC	4 to 273x Less
GHG (CO$_2$e)	1.4x More

Flares meeting current BACT also have a significantly lower greenhouse gas impact compared to older flares. However, new BACT flares still result in about 50% more greenhouse gas emissions than current engines (on a CO$_2$e basis).

In general, criteria pollutant impacts have an immediate impact on public health and as such are typically given greatest weight. GHG gas goals set by AB32 and companion legislation target the long term control strategy to address global warming.   Both issues have merit and deserve attention. One additional element that needs to be noted is energy conservation and the potential wasting of an available energy source (biogas) which is neither drilled nor mined.

CONCLUSION

The technology demonstration projects have shown that technology is available that can achieve significant reductions in NOx, VOC, and CO. Since the 2008 amendment of Rule 1110.2, oxidation catalyst and SCR technology has been effective in reducing pollutant emissions cost effectively for natural gas engines. At the time of the Interim Technology Assessment of 2010, this technology was in the early stages of being explored for the control of biogas engines as well. Since then, the demonstration project at OCSD was successfully completed for the control of biogas emissions from a digester gas facility. In addition, a sufficient amount of data over almost three years was obtained from Ox Mountain Landfill, demonstrating that the control of emissions from a landfill gas-fired engine is achievable on a consistent basis. The utilization of biogas cleanup with siloxane removal has proven essential for the protection of engine components and catalysts. Biogas cleanup systems are currently in use for the protection of engines as

well as microturbines and turbines in the District today. These same systems can also clean the biogas effectively to protect the post-combustion catalytic controls as well.

In addition to catalyst technology, other technologies have emerged as viable alternatives such as the NOxTech system and Hydrogen Injection. Furthermore, technologies such as fuel cells and Flex Energy are viable alternatives for the replacement of IC Engine generated power altogether. The proposed compliance schedule is reasonable, and will allow facilities the needed time to procure, design, and install these systems. Additionally, the compliance schedule will allow enough time for other technologies to be demonstrated and will give facilities more options for compliance.

Alternatives also exist for those facilities, especially landfills, that have closed and whose biogas supply is decreasing below the usable level for IC Engines. In this case, the other alternatives that may be used are boilers, microturbines, or Flex Energy. It is ultimately an operator's decision to flare the biogas, as this also remains as an alternative. However, flaring is still viewed as undesirable due to the pollutant impacts and trade-offs. Cost effective technologies exist that can preclude flaring and still maintain a facility's power-generating capacity with the remaining amount of landfill gas.

The cost effectiveness analysis based on actual data for a digester gas facility shows that the technology is scalable and cost effective for digester gas engines of all sizes. From a dollars per kilowatt standpoint, the analysis shows that the cost of power production will not exceed the cost of purchasing the same power from the grid.

The proposed limits of Rule 1110.2 are feasible and cost effective. Technologies exist today that can achieve these emission limits within the compliance schedule in the Staff proposal. Given the aforementioned cost effective controls and reasonable compliance schedule, increased flaring is not anticipated to occur. On this basis, Staff recommends to move forward with Proposed Amended Rule 1110.2 while maintaining a commitment to continue working with the regulated community in monitoring the performance of on-going demonstration projects to assure that the compliance schedule is reasonable.

ATTACHMENT A

COST EFFECTIVENESS CALCULATIONS FOR RULE 1110.2 REQUIREMENTS FOR BIOGAS ENGINES

Gas Cleanup System + Oxidation Catalyst + SCR (20-year Equipment Life) – Cost basis is OCSD pilot study demonstration

	Digester	Digester	Digester	Digester	Digester	Digester	Landfill	Landfill	Landfill	Landfill	Landfill
BHP	4200	3471	1600	1000	500	250	4200	3471	2700	2000	1500
Installed Equipment, $ (Note 1)	2,240,791	1,989,529	1,230,965	921,665	602,807	395,072	2,345,061	2,082,529	1,781,763	1,479,753	1,239,133
Equipment minus Catalyst, $	2,102,364	1,875,129	1,178,231	888,707	586,328	386,832	2,206,634	1,968,129	1,692,774	1,413,835	1,189,695
Added Cleanup w/20% contingency (Note 2)	420,473	375,026	235,646	177,741	117,266	77,366	441,327	393,626	338,555	282,767	237,939
Catalyst Cost, $ (Note 3)	138,427	114,400	52,734	32,959	16,479	8,240	138,427	114,400	88,989	65,918	49,438
Installed Equipment w/20% contingency, $	**2,661,264**	**2,364,555**	**1,466,611**	**1,099,407**	**720,073**	**472,438**	**2,786,388**	**2,476,155**	**2,120,318**	**1,762,520**	**1,477,072**
Project Management & Installation Supervision, $ (Note 4)	361,107	298,429	137,565	85,978	42,989	21,494	361,107	298,429	232,140	171,956	128,967
Total Initial Investment, $	**3,022,371**	**2,662,984**	**1,604,176**	**1,185,384**	**763,062**	**493,933**	**3,147,495**	**2,774,584**	**2,352,458**	**1,934,475**	**1,606,039**
Sorbent Replacement, $/yr (Note 5)	165,600	138,000	69,000	103,500	51,570	12,420	276,000	276,000	138,000	207,000	103,500
Catalyst Replacement, $/yr (every 2yr, Note 6)	69,213	57,200	26,367	16,479	8,240	4,120	69,213	57,200	44,494	32,959	24,719
Reactant, $/yr (Note 7)	22,869	18,900	8,712	5,445	2,723	1,361	22,869	18,900	14,702	10,890	8,168
Reduced Power Production, $/yr (Note 8)	2,859	1,200	1,089	681	340	170	1,664	1,200	1,069	792	594
Equipment Maintenance, $/yr (Note 9)	-36,479	-30,147	-13,897	-8,685	-4,343	-2,171	-36,479	-30,147	-23,451	-17,371	-13,028
Total Annual Cost, $	**224,064**	**185,153**	**91,272**	**117,420**	**58,530**	**15,900**	**333,268**	**323,153**	**174,815**	**234,270**	**123,953**
Present Value of 20-yr Cost, $ (Note 10)	**6,067,395**	**5,179,213**	**2,844,560**	**2,781,121**	**1,558,484**	**710,013**	**7,676,607**	**7,166,233**	**4,728,196**	**5,118,211**	**3,290,558**
NOx Reduction, tpy (Note 11)	12.6	10.5	4.8	3	1.5	1	12.6	10.5	8.1	6	4.5
VOC Reduction, tpy (Note 11)	29	24	11.1	6.9	3.5	1.7	1.3	1.1	0.8	0.6	0.5
CO Reduction, tpy (Note 11)	538.9	445.4	205.3	128.3	64.2	32.1	538.9	445.4	346.4	256.6	192.5
CO Reduction/7, tpy (Note 12)	77.0	63.6	29.3	18.3	9.2	4.6	77.0	63.6	49.5	36.7	27.5
Cost Effectiveness, $ per ton of NOx+VOC+CO/7	**2600**	**2600**	**3100**	**4900**	**5500**	**4900**	**4200**	**4800**	**4000**	**5900**	**5100**
$/kW-hr	**0.012**	**0.013**	**0.015**	**0.024**	**0.027**	**0.025**	**0.016**	**0.018**	**0.015**	**0.022**	**0.019**

Notes for Gas Cleanup + Oxidation Catalyst + SCR:

1	From the OCSD Final Report for a 3,471 bhp engine, the construction subtotal for equipment and labor with contractor contingencies included is $1,989,529.
	The non-catalyst installed cost is assumed to vary with $bhp^{0.6}$ based on general chemical engineering cost estimating practice for tanks and reactors.
	For landfills, the installed cost of the siloxane removal system is higher because of the higher gas volume per BTU supplied to the engine. Additional cost for gas cleanup on a 3,471 bhp engine is $93,000.
2	A 20% contingency to account for possible additional gas cleanup equipment is added to the equipment costs minus catalyst
3	For the OCSD catalysts, there were 16 catalytic oxidizer blocks at $3,450 per block and thirty-two SCR catalyst blocks at $1,850 per block.
	Catalyst cost is assumed to vary directly with bhp.
4	Cost for project management and installation supervision for OCSD was calculated as a 15% contingency of the installed equipment costs, not including the 20% contingency accounting for possible additional gas cleanup equipment.
5	Vender quotes were obtained for non-regenerative activated carbon vessels/media and were sized and bracketed according to flow rate. Change-out frequency is once every month. The total cost for the media replacement was divided by the number of engines per facility to arrive at a per engine cost. The highest cost at each bracketed engine size was used.
	OCSD's media replacement cost from the pilot study was $40,000 for one year on a 3,471 engine.
6	OCSD experienced a partial deactivation of its oxidation catalyst after two years of operation. Staff has accounted for this by using the annual cost for a biannual catalyst replacement.
7	Cost of urea is based on OCSD's annual cost. Reactant cost is assumed to vary directly with horsepower.
8	Pressure drops across the siloxane removal and SCR systems are assumed to be 3" H2O each. Calculated reduction in power production is 0.147%.
	Cost of reduced power is: bhp x 0.00147 x 8,000 hrs/yr x 0.746 kW/bhp x 0.97 generator efficiency (kWh/yr)
	For landfill gas the power reduction is 0.161% because the higher volume of landfill gas per BTU supplied to the engine. Cost of power is $0.08/kWh for digester gas (cost of grid power) and $0.0425/kWh for landfill gas power (typical wholesale price based on price SCE paid for power from El Sobrante landfill [2002 contract]).
	Electrical costs for OCSD's pilot study were $1,200/yr.
9	OCSD's reduced engine maintenance was subtracted from its equipment maintenance for the pilot study. This cost is assumed to vary directly with horsepower.
10	The present worth value (PWV) is calculated for a project life of 20 years at an interest rate of 4%.
11	Baseline NOx is 36 ppmvd corrected to 15% O2 for engines equal to or greater than 500 bhp and 45 ppmvd corrected to 15% O2 for engines smaller than 500 bhp.
	Baseline VOC is 40 ppmvd corrected to 15% O2 for landfill gas engines and 250 ppmvd corrected to 15% O2 for digester gas engines.
	Baseline CO is 2000 ppmvd corrected to 15% O2.
	Conversion of ppmvd corrected to 15% O2 to g/bhp-hr was based on an engine efficiency of 33% (based on higher heating value), which was the average for biogas engines in the engine survey conducted for the 2008 amendment. This includes a correction of 3% greater volume of combustion products (corrected to 15% O2) due to the CO2 in the fuel.
	The emission reduction calculations assume 8,000 hrs/yr of engine operation.
12	The CO reductions are discounted by 1/7 due to its reduced ozone formation potential.

NOxTech System (20-year Equipment Life) – Costs provided by NOxTech

	Digester	Digester	Digester	Digester	Digester	Digester	Digester	Landfill	Landfill	Landfill	Landfill	Landfill	Landfill
BHP	4200	3471	1600	1350	1000	500	250	4200	3471	2700	2000	1500	1350
Installed Equipment, $													
Equipment Cost, $ (Note 1)	960,000	800,000	400,000	400,000	400,000	400,000	400,000	960,000	800,000	800,000	400,000	400,000	400,000
Installation Cost, $ (Note 2)	250,000	200,000	100,000	100,000	100,000	100,000	100,000	250,000	200,000	200,000	100,000	100,000	100,000
Installation Cost Contingency, $ (Note 3)	300,000	300,000	300,000	300,000	300,000	300,000	300,000	0	0	0	0	0	0
Project Management & Installation Supervision, $ (Note 4)	31,742	26,452	13,226	13,226	13,226	13,226	13,226	31,742	26,452	26,452	13,226	13,226	13,226
Total Initial Investment, $	1,541,742	1,326,452	813,226	813,226	813,226	813,226	813,226	1,241,742	1,026,452	1,026,452	513,226	513,226	513,226
Reactant, $/yr (Note 5)	37,952	31,365	14,458	12,199	9,036	4,518	2,259	37,952	31,365	24,398	18,073	13,554	12,199
Reduced Power Production, $/yr (Note 6)	68,365	56,499	26,044	21,975	16,277	8,139	4,069	53,041	43,834	34,098	25,258	18,943	17,049
Equipment Maintenance, $/yr (Note 7)	16,000	16,000	8,100	8,100	8,100	8,100	8,100	16,000	16,000	16,000	8,100	8,100	8,100
Total Annual Cost, $	122,318	103,864	48,602	42,274	33,414	20,757	14,428	106,993	91,199	74,496	51,430	40,598	37,348
Present Value of 20-yr Cost, $ (Note 8)	3,204,042	2,737,965	1,473,728	1,387,724	1,267,319	1,095,312	1,009,308	2,695,780	2,265,852	2,038,847	1,212,161	1,064,947	1,020,783
NOx Reduction, tpy (Note 9)	12.6	10.5	4.8	4.1	3	1.5	1	12.6	10.5	8.1	6	4.5	4.1
VOC Reduction, tpy (Note 9)	29	24	11.1	9.3	6.9	3.5	1.7	1.3	1.1	0.8	0.6	0.5	0.4
CO Reduction, tpy (Note 9)	538.9	445.4	205.3	173.2	128.3	64.2	32.1	538.9	445.4	346.4	256.6	192.5	173.2
CO Reduction/7, tpy (Note 10)	77.0	63.6	29.3	24.7	18.3	9.2	4.6	77.0	63.6	49.5	36.7	27.5	24.7
Cost Effectiveness, $ per ton of NOx+VOC+CO/7	1400	1400	1600	1800	2200	3900	6900	1500	1500	1700	1400	1600	1700
$/kW-hr	0.007	0.007	0.008	0.009	0.011	0.019	0.035	0.006	0.006	0.007	0.005	0.006	0.007

Notes for NOxTech System:

1	NOxTech provided the following cost information:
	Equipment cost for NOxTech unit sized for 1 engine at 1.5 MW max rating = $400,000. 2 units are required for engines greater than 1.5 MW and less than 3 MW = $800,000. A discount is offered for 3 or more units purchased simultaneously = $960,000 for engines greater than 3 MW.
	If a single unit treats multiple engines with a maximum total rating of 1.5 MW, the cost is $450,000.
	These installation costs are "turn-key." They are site-specific and depend on many factors. The installation costs provided by NOxTech are intended to be typical.
2	Installation costs, including urea tank, are $100,000 for 1 unit treating 1 engine up to 1.5 MW, $200,000 for 2 units treating engines greater than 1.5 MW and less than 3 MW, and $250,000 for 3 units treating engines greater than 3 MW.
	For a single unit treating multiple engines with a maximum total rating of 1.5 MW, the cost is $150,000.
3	EMWD's installation costs were $400,000 for the EGR system. There were also additional equipment and design costs reported that may be site-specific, depending on operating characteristics. The added engineering costs are not independently verifiable. As part of the demonstration project, EMWD incurred added design costs that are not anticipated to be included as a part of future off-the-shelf technology. The additional costs are presented here merely as a worst case and are not expected to be incurred by future end users. The added EGR costs do not apply to landfills because there is no expected natural gas supplementation that would necessitate an EGR system.
4	Project management and installation supervision is assumed to be the same ratio to non-catalyst installed equipment as the OCSD project. For the Interim Technology Assessment, this cost was estimated to be $36,000 for OCSD labor for project management and installation supervision of $1,096,000 of non-catalyst equipment cost. For OCSD's actual non-catalyst equipment cost, which was $1,875,129, the project management and installation supervision cost is approximately $62,000.
5	Reactant is urea. Stoichiometry is 1 pound of urea to treat 1 pound of NOx. Cost of urea is $1.50 per gallon based on information provided by NOxTech. Reactant cost is assumed to vary directly with horsepower.
6	Reduction in power production is caused by biogas use in NOxTech reactor and pressure drop across NOxTech system. Fuel use is assumed to be 5% of full-load engine fuel, and pressure drop is assumed to be 3"H2O. Calculated reduction in power production is 0.133%.
	Reduced power output is: bhp x 0.746 kW/bhp x 8,000 hrs/yr x 0.00133 x 0.97 generator efficiency (kWh/yr).
	It is assumed that use of 5% of full-load engine fuel in NOxTech chamber further reduces power by 5% in landfill gas case, but digester gas can be replaced by natural gas.
	Cost of reduced power is $0.08/kWh for digester gas case and $0.0425/kWh for landfill gas case. Cost of natural gas is $0.50 per them.
7	Information provided by NOxTech: annual maintenance for 1 NOxTech unit is estimated to be $8,100 and $16,000 for 2 or more units. The annual maintenance cost for 1 unit treating multiple engines with a maximum total rating of 1.5 MW is $10,000.
8	Same as Note 10 in previous table.
9	Same as Note 11 in previous table.
10	Same as Note 12 in previous table.

ATTACHMENT B

ORANGE COUNTY SANITATION DISTRICT CATALYTIC OXIDIZER/SCR PILOT STUDY FINAL REPORT, JULY 2011

Orange County Sanitation District

10844 Ellis Avenue • Fountain Valley CA 92708-7018

Retrofit Digester Gas Engine with Fuel Gas Clean-up and Exhaust Emission Control Technology

South Coast Air Quality Management District Contract #10114

Pilot Testing of Emission Control System Plant 1 Engine 1

Orange County Sanitation District Project No. J-79

FINAL REPORT

July 2011
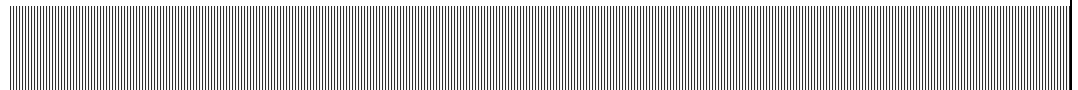
Report Prepared By:

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Glossary of Terms

Acronym	Definition
ARB	Air Resources Board
AQMD	Air Quality Management District
BACT	Best Available Control Technology
bhp	Brake horse power
CEMS	Continuous emissions monitoring systems
CI	Compression Ignition
CO	Carbon monoxide
CO_2	Carbon dioxide
Cpsi	Cells per square inch
°C	Degrees Centigrade
°F	Degrees Fahrenheit
DG	Digester Gas
DGCS	Digester Gas Cleaning System
EPA	Environmental Protection Agency
FTIR	Fourier Transform Infrared
GC/MS	Gas chromatography-mass spectrometry
H_2S	Hydrogen sulfide
HHV	Higher Heating Value
HI	Hazard Index
hp	Horse power
HRU	Heat Recovery Unit
IC	Internal Combustion
in. w.c.	Inches water column
KW	Kilowatt
MDL	Method Detection Limit
MMscf	Million standard cubic feet
MW	Megawatts
N_2	Nitrogen
NG	Natural Gas
NMHC	Non-methane hydrocarbons
NMNEOC	Non-methane non-ethane organic compounds
NO_2	Nitrogen dioxide
NO_x	Nitrogen oxides
O_2	Oxygen
OCSD	Orange County Sanitation District
PEMS	Parametric Emission Monitoring System
PM	Particulate matter
ppbv	Parts per billion by volume
ppm	Parts per million
ppmv	Parts per million by volume
psig	Pounds per square inch gage
RPM, rpm	Revolutions per minute
SCAQMD	South Coast Air Quality Management District
SCAT	Synthetic gas matrix catalyst activity test
scfm	Standard cubic feet per minute

Acronym	Definition
SI	Spark-ignited
VOCs	Volatile organic compounds
XRF	X-ray fluorescence

Acknowledgements

This pilot study could not have been accomplished without the support and cooperation of the following people (listed in alphabetical order), as well as numerous others who contributed to the performance of the project.

Executive Summary

The Orange County Sanitation District (OCSD) owns and operates two wastewater treatment plants in Orange County, California, Reclamation Plant No. 1 (Plant 1) in Fountain Valley and Treatment Plant No. 2 (Plant 2) in Huntington Beach. Each plant operates a Central Power Generation System (CGS) to produce electrical power for the plant operations using large digester gas-fired internal combustion (IC) engines. Plant 1 has three (3) 2.5-megawatt (MW) internal combustion (IC) engines and Plant 2 has five (5) 3-MW IC engines, fueled primarily by digester gas (a biogas) and supplemented by small amounts of natural gas.

Plants 1 and 2 are within the jurisdiction of the South Coast Air Quality Management District (SCAQMD). SCAQMD has established regulations aimed at reducing and controlling air emissions from combustion sources, such as the engines at the plant CGS, including Rule 1110.2 *Emissions from Gaseous and Liquid-fueled Internal Combustion Engines*. In February 2008, SCAQMD amended Rule 1110.2, lowering the emission limits for nitrogen oxides (NOx), volatile organic compounds (VOCs), and carbon monoxide (CO) for IC engines. The amended rule also requires biogas-fueled engines to meet new lower NOx, CO, and VOC emission limits effective July 2012.

In April 2008, OCSD engaged Malcolm Pirnie to conduct an emission reduction technology evaluation of the CGS engines in order to identify technologies for reducing NOx, CO, and VOC emissions to meet the new Rule 1110.2 emission limits, including combustion modification and post-combustion control. After a detailed review of different technologies, the post-combustion technology of catalytic oxidizer/selective catalytic reduction (Cat Ox/SCR) system with digester gas cleaning system (DGCS) using carbon adsorption was recommended as the technology with the most potential for meeting the future Rule 1110.2 emission limits. OCSD then embarked on a full-scale pilot study of the recommended technology on Engine 1 at Plant 1 to evaluate if the future amended Rule 1110.2 limits can be met for their digester gas-fired IC engines. Because SCAQMD recognized that the future emission limits in amended Rule 1110.2 were "technology-forcing," the Governing Board directed staff to conduct a technology assessment to determine if cost-effective and commercially available technologies exist that can achieve these new lower emission limits. SCAQMD issued a grant to OCSD in 2009 (*SCAQMD Contract #10114*) to support the pilot test study at Plant 1 Engine 1, and the operation of the pilot study was granted a Permit to Construct/Operate for an Experimental Research Project by SCAQMD (Application Number 497717) in November 2009. The construction and installation of the pilot study equipment commenced in October 2009; the pilot study testing officially began on April 1, 2010 and officially ended on March 31, 2011.

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Under the pilot study, Engine 1 at Plant 1 was equipped with a catalytic oxidizer to remove CO and VOCs, followed by an SCR system with urea injection to remove NOx (both systems supplied by Johnson Matthey). Due to space limitations at Plant 1, the catalytic oxidizer and SCR systems were mounted on a platform 14 feet above an onsite access road. Engine 1 is fueled primarily by digester gas, supplemented by natural gas. Digester gas contains low concentrations of siloxanes and other compounds which convert to sand-like particulate during combustion (silica) that contribute to rapid degradation of engines, gas turbines, and boilers, along with increased maintenance requirements. In addition, the silica also adheres to the catalyst media of the post-combustion control equipment. Therefore, a digester gas cleaning system (DGCS) was installed (supplied by Applied Filter Technology) to remove these contaminants from the digester gas before it was combusted in Engine 1. The potential for carbon media breakthrough was routinely monitored for using Draeger® tubes to measure hydrogen sulfide (H_2S) concentrations. Samples of the digester gas before and after the DGCS were also sent for laboratory analysis to measure for siloxane, H_2S, and VOCs that could indicate media breakthrough. During the study, inlet and outlet concentrations of CO, NOx, and VOCs were measured to determine the potential reductions in emissions due to the Cat Ox/SCR system. Sampling methods included:

- CO: Portable analyzer, SCAQMD Method 100.1

- VOCs: SCAQMD Methods 25.1/25.3

- NOx: Portable analyzer, SCAQMD Method 100.1

- Aldehydes: Modified CARB Method 430, SCAQMD Method 323 (formaldehyde)

- Ammonia slip (free ammonia): Modified SCAQMD Method 207.1 and Draeger® tubes

In addition, data from the OCSD's continuous emissions monitoring system (CEMS) was collected at the engine exhaust (inlet to the Cat Ox system) for NOx and at the stack exhaust for NOx, CO, and O_2. All CEMS data is based on 15-minute averages. Sampling was also performed for formaldehyde, acetaldehyde, and acrolein as required by the Experimental Research Project permit. In addition, ammonia levels in the stack exhaust were also measured to quantify potential ammonia slip, a result of the urea injection used in the SCR system. The overall conclusions of the pilot study are as follows:

1. The average NOx concentration at the stack exhaust after the pilot study controls was approximately 7 ppmv, below the 11 ppmv required under amended Rule 1110.2. The lowest NOx stack exhaust concentration met consistently under all valid conditions was 16 ppmv. While there were some periods (i.e., 15-minute block averages) where the NOx stack exhaust concentration was above 11 ppmv, after screening these periods, 181 periods out of 21,285 total operating periods (approximately 5,321 hours) remained as valid NOx excursions above the new Rule

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1110.2 limit. These periods occurred during 61 separate events and accounted for less than 0.9% of the total measurement periods during the pilot study. Excursions were considered valid when they occurred during periods/events when the percentage of natural gas increased to above 5% of the fuel blend, when engine loads exceeded the loads mapped during the SCR system commissioning, or during periods/events not attributable to engine start-up or operational /system adjustments. An implication of these remaining periods are that the 11 ppmv limit is too conservative an emission limit, and may warrant further evaluation and potential increase and/or a specified percentage of allowable excursions.

2. SCR systems similar to the Johnson Matthey® system used in the present pilot study are commercially available for combustion units fueled by single component fuels, such as natural gas. Although the SCR system did not consistently meet the 11 ppmv limit with the digester gas/natural gas fuel blend in the pilot study, it did demonstrate a significant reduction in NOx emissions.

3. The free ammonia concentration was below 0.5 ppmv during all testing events using either SCAQMD compliance method 207.1, and below the Method Detection Limit (MDL) using Draeger® tubes.

4. The maximum CO concentration at the stack exhaust using the CEMS data was 42.2 ppmv, well below the amended Rule 1110.2 emission limit of 250 ppmv.

5. The maximum VOC concentration at the stack exhaust was found to be 4.95 ppmv, and was consistently well below the 30 ppmv limit in amended Rule 1110.2.

6. The use of the combined Cat Ox/SCR system in the pilot study resulted in significant reductions in CO, VOC, and NOx.

7. The DGCS system, in general, removed siloxanes from the digester gas to below Method Detection Limit (MDL) levels and significantly reduced sulfur compounds and VOCs successfully reducing catalyst masking which should lead to extended catalyst life. Additional benefits of the contaminant removal were significant improvements in engine maintenance requirements and lower O&M costs.

8. The total capitals cost to design, procure, and install a digester gas cleaning vessel to clean all the digester gas to the three Plant 1 engines, and a Cat Ox/SCR system with auxiliary equipment for Engine 1 is estimated to be $2,300,000. The annual operations and maintenance (O&M) cost for these systems at Plant 1 is approximately $59,000. Assuming a 20-year lifespan, the total annualized cost (capital cost plus O&M) for the DGCS and Cat Ox/SCR systems for Plant 1 Engine 1 is $227,000.

9. The cost effectiveness analysis (based on dollars per ton of NOx, VOC, and CO emissions reduced) was developed for two scenarios: Scenario 1 assumed that the uncontrolled emissions were developed based on current permit limits (i.e., 45 ppmv, 209 ppmv, and 2,000 ppmv, respectively), and Scenario 2 assumed that the uncontrolled emissions were developed based on the results from the 2011 Annual Compliance Test for Engines 2 and 3. Both scenarios assumed that the controlled emissions were based on the Rule 1110.2 limits of 11 ppmv for NOx and 30 ppmv

for VOCs, and the pilot testing results of 15 ppmv for CO. Under these assumptions, the cost effectiveness for Scenarios 1 and 2 is $7,987 and $17,585, respectively, per ton of NOx plus VOCs reduced. The cost effectiveness for Scenarios 1 and 2 is $636 and $3,546, respectively, per ton of CO reduced. Note that the cost effectiveness for CO is conservative since the annualized cost is based on the entire system including the SCR and urea injection system. The annualized cost and emissions reduced calculations were based on operating each engine for a maximum of 6,000 hours per year.

1. Project Background and Objectives

1.1. Background

The Orange County Sanitation District (OCSD) owns and operates two (2) wastewater treatment plants that serve 21 cities and three special districts in the central and northwest Orange County, California, Reclamation Plant No. 1 (Plant 1) in Fountain Valley and Treatment Plant No. 2 (Plant 2) in Huntington Beach. In addition to the wastewater treatment processes, each plant operates a Central Power Generation System (CGS) to produce electrical power for the plant operations using large digester gas-fired internal combustion (IC) engines. Plant 1 has three (3) 2.5 megawatt (MW) internal combustion (IC) engines and Plant 2 has five (5) 3 MW IC engines, fueled primarily by digester gas (a biogas) and supplemented by small amounts of natural gas. Biogas, a by-product of the anaerobic digestion of wastewater solids, is classified as a renewable fuel, and the combustion of the biogas in the IC engines provides a beneficial reuse of a waste product.

Plants 1 and 2 are within the jurisdiction of the South Coast Air Quality Management District (SCAQMD). SCAQMD has established regulations aimed at reducing and controlling air toxic emissions from combustion sources, such as the engines at the plant CGS, including Rules 1110.2, 1401 and 1402. Under Contract J-79 Air Toxics Emission Reduction Strategic Plan (2003), Malcolm Pirnie was retained by the OCSD to perform an evaluation of regulations addressing air toxic requirements under the rules. Malcolm Pirnie prepared an emission reduction study/air toxics strategic plan for the OCSD to comply with the NOx emission limit under Rule 1110.2 for IC engines. The study also addressed acceptable risk levels from Plant 1 and Plant 2 to comply with Rules 1401 and Rule 1402 (*Air Toxic Emission Reduction Strategic Plan* (Malcolm Pirnie, 2004) and *2012 Air Toxic Emission Reduction Strategic Plan* (Malcolm Pirnie, 2006)). The study identified the formaldehyde emissions from the CGS engines as a significant contributor to the overall risk levels, and also identified a catalytic oxidizer system with a digester gas cleaning system (DGCS) as a viable control technology to reduce the formaldehyde emissions from the digester gas-fired IC engines. This system was evaluated in a full-scale pilot study of a catalytic oxidizer system on Engine 3 at Plant 2 (*Catalytic Oxidizer Pilot Study* (Malcolm Pirnie, 2007)).

A catalytic oxidizer system is one of the most promising technologies for controlling carbon monoxide (CO) and volatile organic compounds (VOC) emissions from combustion units burning natural gas. However, fouling or rapid performance degradation of the catalytic oxidizers has been an issue for engines burning digester gas due to contaminants in the digester gas, such as volatile methyl-siloxanes and sulfurous compounds that tend to foul the catalytic oxidizers. Therefore, the use of a digester gas

cleaning system to prevent the contaminants in the digester gas from fouling and/or masking the catalyst was also evaluated.

In February 2008, SCAQMD further amended Rule 1110.2 to reduce emission limits for nitrogen oxides (NOx), VOCs, and CO, and also to improve/enhance monitoring, recordkeeping and reporting requirements for IC engines. Biogas engines were given until July 2012 to meet new lower emission limits. Malcolm Pirnie conducted an emission reduction technology evaluation of the CGS engines and identified several technologies for reducing NOx, CO, and VOC emissions, including combustion modification and post-combustion control (*Feasibility Study for a Technology Evaluation for Compliance with Amendments to SCAQMD Rule 1110.2 – Emissions from Gaseous and Liquid-fueled Internal Combustion Engines* (Malcolm Pirnie, 2008)). After a detailed review of the different technologies, the post-combustion technology of catalytic oxidizer/selective catalytic reduction (Cat Ox/SCR) system with DGCS using carbon adsorption was recommended as the technology with the most potential for meeting the future Rule 1110.2 emission limits.

In 2009, OCSD embarked on a pilot study of this recommended technology on Engine 1 at Plant 1 to evaluate if the future Rule 1110.2 limit can be met for their biogas-fired IC engines. Design of the pilot system included an SCR system for NOx emission reduction, an oxidation catalyst unit for CO and VOC reduction (including formaldehyde), and a DGCS upstream from the IC engines for removal of siloxanes to prevent fouling of the catalysts. Additional benefits of the DGCS include the removal of total reduced sulfur and total volatile organic compounds. To supplement and support this study, SCAQMD issued a grant to OCSD (SCAQMD Contract #10114, 2009) for this pilot test study, and will be evaluating the data collected as part of their technology assessment of the feasibility of biogas engines achieving the future Rule 1110.2 emission limits for biogas-fired engines. The operation of the pilot study was granted a Permit to Construct/Operate for an Experimental Research Project by SCAQMD (Application Number 497717) (Appendix A-1).

1.2. SCAQMD Rule 1110.2

The IC engines at OCSD are subject to Rules 1110.2. Rule 1110.2 provides emission limits and monitoring requirements for all stationary and portable engines over 50 brake-horsepower (bhp). Rule 1110.2 (*Emissions from Gaseous- and Liquid- Fueled Engines*) was promulgated to reduce the NOx, CO and VOC emissions from engines over 50 bhp. On February 1, 2008, Rule 1110.2 was amended in order to achieve further emissions reductions from stationary engines based on the cleanest available technologies. Under the February 2008 amendments to Rule 1110.2 shown below, more stringent NOx, CO, and VOC limits were adopted, to become effective for biogas-fueled engines in July 2012 provided a technology assessment confirms that the limits below are achievable.

- NOx limit was lowered from 36 ppm (or ~ 45 ppm*) to 11 ppm at 15% O_2.

- VOC limit was lowered from 250 ppm* to 30 ppm at 15% O_2.

- CO limit was lowered from 2,000 ppm to 250 ppm at 15% O_2.

* Existing limits allow for an alternative emission limit for OCSD engines based on the engine efficiency correction factor.

The rule allows for some exemptions, including an exemption during engine start-up, to allow for sufficient operating temperatures to be reached for proper operation of the emission control equipment. The start-up period is limited to 30 minutes unless a longer period is approved for a specific engine by the Executive Officer and is made a condition of the engine permit.

1.3. Objectives

Because the future Rule 1110.2 emission limits shown above are "technology-forcing," the SCAQMD Governing Board directed staff to conduct a technology assessment to determine if cost-effective and commercial technologies are available to achieve their limits. This pilot study will be used by SCAQMD as part of that technology assessment to evaluate the ability of the biogas-fueled engines at OCSD wastewater treatment plants to meet these future limits.

The objective of this study is to evaluate the effectiveness of a Cat Ox/SCR system with a DGCS as a post-combustion emissions control technology for an IC engine operating on biogas at a wastewater treatment plant. The data collected will be evaluated as part of the technology assessment study for the 2012 biogas engine emission limits under amended Rule 1110.2. Data were gathered on engine performance and emission reductions. Data were also gathered to obtain information for use in full-scale design (e.g., back pressure, impact on heat recovery unit (HRU)), to assess the performance of the DGCS (e.g., siloxane removal, media life), and to determine the economic feasibility of operating the Cat Ox/SCR system and the DGCS.

1.4. Report Organization

This report is organized into the following sections:

- Executive Summary

- Section 1. Project Background and Objectives

- Section 2. Pilot Study Work Plan

- Section 3. Results and Discussion

- Section 4. Cost Effectiveness Analysis

- Section 5. Conclusions and Recommendations

■ Appendices

2. Pilot Study Work Plan

2.1. General Description

The engines at the CGS at both the Fountain Valley Reclamation Plant 1 and Huntington Beach Treatment Plant 2 are lean-burn, spark-ignited IC engines, and have been permitted to operate by SCAQMD. Plant 1 has three (3) 2,500 kilowatts (KW) units, while Plant 2 has five (5) 3,000 KW units. The engines are of conventional four-stroke cycle stationary Vee engine construction. They utilize spark-ignited pre-chamber technology to achieve extremely low NOx emissions. These electrical power generation stations utilize state-of-the-art low emission, spark-ignited, reciprocating engines fueled by digester gas and/or natural gas to drive generators. The engine generators normally operate in parallel with the grid, providing electrical loads at both plants. Excess power at Plant 2 is exported to the local utility. Waste heat energy in the cooling systems and exhaust are extracted and utilized for process heating through heat recovery units on each engine. Plant 2 has the capability to produce additional electrical energy with waste heat energy through use of a steam turbine-generator. Typically, at any given time one unit is down at Plant 1 and two units are down at Plant 2 for maintenance while the remaining units operate over a range of 60-120% load. Once placed on line, an engine will operate approximately 1,000-2,000 hours before being shut down for routine maintenance.

At Plant 1, each of the three IC engines are rated at 3,471 bhp, and each engine can produce up to 2.5 MW of electricity. This pilot study was conducted on Engine 1 at Plant 1 (see Figure 2-1). Details of the three Plant 1 engines, including Engine 1 are shown in Table 2-1.

Based upon a carefully designed series of studies performed for OCSD to meet existing and emerging regulatory standards, the full-scale pilot study of Engine 1 at Plant 1 included a DGCS using carbon media for removal of siloxanes and other harmful contaminants from the digester gas, and post-combustion control technology using a catalytic oxidizer system to reduce emissions of CO and VOCs, and SCR technology with urea injection for controlling of NOx emissions. The engine is equipped with continuous emissions monitoring system (CEMS) at the engine exhaust for measuring NOx concentration entering the Cat Ox/SCR system, and at the stack for measuring NOx, CO, and oxygen (O_2) concentrations after the Cat Ox/SCR system. Figure 2-2 and Appendix A-2 shows a schematic of the overall system.

Construction of the pilot study was initiated in October 2009. During the design and construction for the pilot study, two other projects were also in progress at Plant 1:

- J-79-1 Central Generation Automation. During this project, the engine control systems (ECS) for the CGS at both plants were replaced. The existing ECS at both

facilities were no longer being manufactured and parts replacement was not reliable. The new systems provide automatic load management capability, as well as an emissions monitoring feedback signal for exhaust emissions control.

- J-79-1A Continuous Emissions Monitoring Systems. Installation of a CEMS at the stack outlets of the CGS engines at both plants and NOx inlet analyzers.

Prior to the start of the full-scale pilot study, both J-79-1 and J-79-1A projects were completed at Plant 1 Engine 1 before the pilot system commenced operation in April 2010 and initial performance testing was performed on both the DGCS and Cat Ox/SCR system.

2.2. Digester Gas Cleaning System

Digester gas is generated during the anaerobic digestion of the sewage sludge produced during the wastewater treatment process. This biogas contains contaminants such as hydrogen sulfides (H_2S), VOCs, and low concentrations of volatile siloxane compounds. Siloxane is a compound that is found in numerous consumer personal products and thus enters the wastewater treatment system. During combustion, the siloxanes convert to silica, sand-like particulate that deposit on the surfaces of combustion equipment contributing to a rapid degradation of engines, gas turbines, and boilers, along with increased maintenance requirements. In addition, the silica also adheres to the catalyst media of any post-combustion control equipment. These deposits can cause masking of the catalyst sites that significantly reduces the effectiveness of the catalyst. Based upon the pilot testing performed at Plant 2 (Malcolm Pirnie, 2008), the DGCS was shown to be successful in removing contaminants such as siloxanes, H_2S, and VOCs from the digester gas, and extending the catalyst performance life comparable to an IC engine combusting natural gas. In addition, the use of the DGCS resulted in a significant reduction in operations and maintenance (O&M) costs for the CGS engines.

2.2.1. DGCS Technology and Equipment

In order to minimize the masking effect from the siloxanes and sulfurous compounds, and prevent the deterioration of the post-combustion Cat Ox/SCR system installed for the pilot study, the digester gas was scrubbed to remove these contaminants prior to combustion. A DGCS (SAG™) supplied by Applied Filter Technology, Inc. (AFT) and consisting of a single carbon media vessel was installed at Plant 1. The SAG™ process was developed to remove siloxanes and other contaminants considered harmful to power generation equipment including engines, gas turbines, fuel cells and boilers. The media also treats VOCs, H_2S, and other sulfides. The vessel contains three layers of specialized graphite-based molecular sieves, which are small to large black pellets or spheres, capable of removing, through adsorption, the siloxanes from the biogas. The sieve types and layer depths (and the resulting vessel size) are determined by gas analysis to confirm system performance parameters. The biogas enters the SAG™ vessel at the top and proceeds down through the layers of sieves, exiting through flanged septa connected to a

manifold header. Each layer removes a specific type of contaminant and, in turn, protects the layer following it by removing contaminants that can foul it. The SAG™ siloxane media is a loose pellet form of polymorphous graphite carbon-based media specifically designed for removal of siloxanes in methane, and can be disposed of as a non-hazardous waste at a local approved site. Following system start-up, the vessel is allowed to process the biogas until there is breakthrough. In the present pilot study, the potential for media breakthrough was conservatively determined using H_2S as a marker. Once the potential for breakthrough is determined, the media is scheduled for change out. The vessel is then taken out of service, the media is replaced, and the vessel is returned to service.

The SAG™ unit used in the pilot study was a single stage, 7.5 ft diameter by 8 ft straight -sided dished downflow carbon steel filter unit. The unit contained 9,900 lbs of SAG™ three-stage media for siloxane removal. It includes interior high build epoxy coating and corrosion allowance vessel plate thickness. The DGCS system was sized and designed such that it could be used to clean all the digester gas produced at Plant 1. The DGCS was designed for the conditions presented in Table 2-2.

The DGCS was located along the south side of the Gas Compressor Building. Figure 2-3 shows a photograph of the DGCS at the Plant 1.

2.2.2. DGCS Measurement and Monitoring Methods

One objective of this pilot study was to assess the performance of the DGCS with respect to the removal of siloxanes and other contaminants, along with the life of the removal media. Based on the pilot testing performed at Plant 2 Engine 3, the DGCS proved successful in removing contaminants from the digester gas. The catalyst at Plant 2 Engine 3 fouled rapidly after combustion of uncleaned digester gas. Catalyst performance with the DGCS was comparable to that of a catalyst installed on the exhaust of an IC engine operating on natural gas.

Testing was performed to determine if the equipment met the design specifications. Two sampling methods are commonly used for measuring siloxanes: gas chromatography-mass spectrometry (GC/MS) and the wet chemistry method. Digester gas analyzed using GC/MS can be collected using either Tedlar® bags or canisters. The wet chemistry method requires samples to be collected using methanol impingers over a two to four hour sampling period, and then sent to a lab for analysis. After discussions with several certified laboratories, and review of several published papers, both methods were found to have merit; however, the collection of the samples using Tedlar® bags for measurement by GC/MS provided the most flexibility for minimum sampling time and equipment required. In the initial performance testing of the gas cleaning system, samples were collected using Tedlar® bags, canister, and methanol impinger methods at the digester gas inlet location at the same time, during the same day, and the analytical results were compared to determine the most appropriate method for analyzing

performance breakthrough. During the initial test, individual measurements of inlet total siloxane, consisting of, hexamethylcyclotrisiloxane (D3), octamethylcyclotetrasiloxane (D4), decamethylcyclopentasiloxane (D5), hexamethyldisiloxane (L2), octamethyltrisiloxane (L3), and any other siloxane compounds identifiable according to the test method, were recorded.

For the sampling performed using Tedlar® bags at the DGCS inlet, the samples were collected and sent to a certified laboratory for the analysis of speciated siloxanes using TO-14/15, speciated VOCs using TO-15, total reduced sulfides using EPA 1023 Method 16B, or ASTM Procedure D-5504 GC/SCD, and the overall gas components and quality (% CH_4, % CO_2, % N_2, heating value using) using EPA Method 3C. One sample was also collected at the DGCS outlet to confirm that the DGCS met performance standards for all siloxanes to be measured as non-detect (i.e., below Method Detection Limit, MDL).

Samples were also collected in SUMMA® canisters at the DGCS inlet and sent to a certified laboratory for analysis of speciated siloxanes. In addition, speciated VOCs were analyzed using TO-15, total reduced sulfides were analyzed using ASTM D-5504, and overall gas components and quality (% CH_4, % CO_2, % N_2, heating value) was analyzed using ASTM D-1946.

The wet chemistry method was used at the DGCS inlet. During the test, the digester gas sample was collected using methanol impingers over a 4-hour period, and the samples were sent to the laboratory for individual measurements of inlet total siloxane.

Hydrogen sulfide testing was conducted weekly using Draeger® tubes. The H_2S concentration was used as an indicator that the media was nearing saturation. Breakthrough itself was determined to occur when the total siloxane concentration at the outlet of the carbon adsorber was above the MDL or when the H_2S concentration reached 15 ppm. Originally, the monitoring plan recommended by the vendor, AFT, was to use an H_2S concentration threshold of 5 ppm at the outlet to trigger siloxane and siloxane compound testing every week until breakthrough occurred. However, a more conservative approach for media saturation was used for the pilot study. Saturation and media replacement was triggered when measurable H_2S levels (generally around 1 ppm) were found using the Draeger® tube readings. The procedures used for taking the Draeger® tube measurements are shown in the Monitoring Test Procedure in the CD attached to this report. OCSD staff also performed routine sampling of the digester gas for H_2S (Draeger® tubes), sampling for reduced sulfides (SCAQMD Method 307-91), and sampling for speciated VOCs (TO-15).

2.2.3. Selection of DGCS Sampling Method

Details of the DGCS performance test are presented in a Technical Memorandum (Malcolm Pirnie, May 5, 2010) found in Appendix A-3. Table 2-3 summarizes the results of the comparison of siloxane sampling methods.

As shown in the summary of the results shown in the table, the Tedlar® bag sampling method detected the highest level of total siloxane. In addition, the Tedlar® bag sampling method provided the most flexibility for minimum sampling time and equipment required. Based on these criteria, the Tedlar® bag method was chosen as the sampling method for the digester gas sampling for siloxanes.

2.3. Cat Ox/SCR System

Based on the results of the Catalytic Oxidizer Study on Plant 2 Engine 3 (Malcolm Pirnie, 2007) and the Feasibility Study (Malcolm Pirnie, 2008), the combination of a catalytic oxidizer followed by selective catalytic reduction equipment with urea injection provided by Johnson Matthey (JM) was selected for the pilot study.

Catalytic oxidation is a post-combustion control technology which has been commercially proven to reduce CO, VOCs and air toxics, including formaldehyde and acrolein, from engines burning natural gas. There is, however, limited performance data for an engine fired with digester gas, either with or without a gas cleaning system. The digester gas, which is generated during the biological consumption of solids that are collected during the wastewater treatment process, contains low but detrimental concentrations of siloxane compounds, which convert to silica during combustions and deposit on the surfaces of post-combustion equipment, including catalyst media. This fouling of the catalyst, or catalyst masking, significantly reduces the effectiveness of the catalyst. In order to minimize this masking effect, the digester gas can be pre-cleaned to remove these siloxanes prior to combustion.

The Johnson Matthey catalyst elements are manufactured in a "block" form. The catalyst block substrate is made from stainless steel foil that is retained by a stainless steel frame. This structure undergoes a proprietary coating process in which the foil is chemically treated to increase surface area. Active platinum group metal catalysts are then applied. The coating, catalyst composition, and honeycomb pore size were designed by Johnson Matthey to provide optimum durability and pollutant removal efficiency for the specified operating environment.

In the SCR system, the exhaust enters a mixing tube where a stream of atomized urea is introduced into the gas. The urea quantity is controlled by the urea injection control system. Mixing vanes distribute the atomized particles throughout the exhaust gas. Ammonia is formed from aqueous urea $((NH_2)_2CO)$ after the urea injection, which involves evaporation of water, thermal decomposition of urea, and finally hydrolysis of

iso-cyanic acid. Evaporation of water is initiated when the aqueous urea is injected into the exhaust gas pipe. This mixture then enters the SCR housing. A chemical reaction between the ammonia from the urea, the exhaust gas NOx component, and SCR catalyst results in the reduction of the NOx into nitrogen (N_2), carbon dioxide (CO_2), and water (H_2O). The basic equations are:

Urea Reaction

$(NH_2)_2CO \rightarrow NH_3 + HNCO$

$HNCO + NOx + O_2 \rightarrow N_2 + H_2O + CO_2$

Ammonia Reaction

$NH_3 + NOx + O_2 \rightarrow N_2 + H_2O + CO_2$
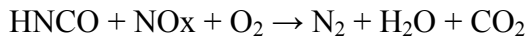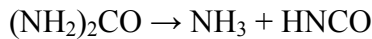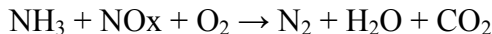
The percent reduction of NOx is determined by the amount of urea introduced into the gas flow.

The Cat Ox/SCR system was installed in a horizontal position on a platform, elevated at a height of approximately 14 feet directly west of Engine 1 at Plant 1. This platform-mounted installation allowed for easy access to the equipment and access to the roadway underneath the platform. Figure 2-4 shows a photograph of the platform installation. The Cat Ox/SCR system was designed for the conditions and performance guarantees presented in Tables 2-1 and 2-4, respectively.

2.3.1. SCR/Catalytic Oxidizer System Technology and Equipment

Oxidation Catalyst Housing. The oxidation catalyst consisted of one Johnson Matthey Model 4040SS-4-30/36 housing for the catalyst at Engine 1. The housing has access doors on both sides of the housing, with four tracks for installing catalyst. One of the tracks houses the initial catalyst supplied, with three tracks available for later expansion if needed. There is a 30-inch flange on the inlet and a 36-inch flange on the outlet of the housing. When completely full of catalyst (4 layers), the total weight of the housing plus the catalyst is about 8,190 pounds. The housing has a number of two ¾ inch ports on the inlet and two ¾ inch ports on the outlet of the oxidation catalyst housing.

Oxidation Catalyst. A total of sixteen (16) whole oxidation catalyst blocks were part of this system. They were arranged 4 blocks wide x 4 blocks high x 1 block deep. [A whole block is approximately 2 feet wide x 2 feet tall x 3¼ inches deep and constitutes approximately 1 ft^3 of catalyst volume.] The cell density of this catalyst is 200 cells per square inch (cpsi). Figure 2-5 shows a photograph of the catalyst.

SCR Catalyst Housing. Johnson Matthey provided a JM Model 4040SS-4-36 housing for the catalyst. The housing was fabricated in 304 stainless steel. Two layers of catalyst were installed and there were two open tracks for addition of another layer if desired at a later date. The housing was equipped with access doors on both sides of the housing.

There are 36-inch inlet and outlet flanges (150# ANSI) provided on the housing. When completely full of catalyst (4 layers), the total weight of the housing plus the catalyst is approximately 8,190 pounds. The housing has a number of two ¾ inch ports on the inlet and two ¾ inch ports on the outlet of the SCR housing for sampling.

SCR Catalyst. The catalyst consists of thirty-two (32) whole SCR catalyst blocks on 200 cpsi metal substrate. They are arranged 4 blocks wide x 4 blocks high x 2 blocks deep. [A whole block is approximately 2 feet wide x 2 feet tall x 3¼ inches deep, and constitutes approximately 1 ft^3 of catalyst volume.]

Urea Injection Control System. This system was designed to control the injection rate of urea into the SCR based on engine load for one fuel blend. During the initial commissioning of the system, the engine load, the urea injection rate, and the NOx and ammonia outlet concentrations were measured and mapped. Mapping refers to the process in which the urea injection rate is correlated to the engine load in order to meet the desired NOx exhaust concentration. The system allowed for up to 25 combinations of engine load versus urea injection rate (set points).

In addition to the load map control, the injection system also uses a system of bias set points to trim the urea injection. The NOx curve bias is a percentage that can be input by the operator to increase or decrease the urea injection rate. This bias is typically set to 0%, but can be modified if engine operation is expected to change the NOx produced in the exhaust emissions. The NOx add bias increases the urea injection rate by an input gallon per hour setting based on the NOx outlet concentration from the stack exhaust CEMS analyzer. When the NOx outlet concentration reaches the level set in the control system, the urea injection rate will increase by the bias set point. The NOx subtract bias decreases the urea injection rate in the same manner. For the pilot test, no NOx subtract bias was set.

The SCR process requires precise control of the urea injection rate. An insufficient injection may result in unacceptably low NOx conversions. An injection rate that is too high can result in release of excessive ammonia emissions. These excess gaseous ammonia emissions are known as "ammonia slip". Under the research permit for this study, the maximum allowable ammonia slip is 10 ppm. Excess ammonia can lead to clogging and equipment problems in downstream equipment. In addition, emissions of ammonia slip to the atmosphere can result in odors and a visible plume. The ammonia slip increases at higher NH$_3$/NOx ratios. The stoichiometric NH$_3$/NOx ratio is approximately 1.

2.3.2.   Cat Ox/SCR Measurement and Monitoring Methods

Preliminary Testing/SCR Urea Injection Mapping. The objective of the preliminary testing was to measure the performance of the system at varying loads and fuel blends

(i.e., digester gas and natural gas), and to map the urea injection system. The CO, NOx, and O_2 concentrations at varying engine loads and fuel distributions at the inlet of the oxidation catalyst and the outlet of the SCR catalyst were monitored for a period of six (6) hours at ten (10)-minute intervals using the TESTO® 350 XL Portable Monitor during startup as part of the preliminary testing. In addition, ammonia measurements were taken at the outlet of the SCR catalyst at ten (10)-minute intervals using Draeger® tubes. A data logger was used to monitor temperature and pressure differential on a real-time basis over the six (6)-hour testing period. Carbon monoxide was also monitored with the TESTO® 350 XL Portable Monitor. Load and fuel distribution of the engine were varied according to the schedule shown in Table 2-5. The recorded data is provided in Appendix C-1.

A secondary objective of the preliminary testing was to provide varying load and fuel scenarios for Johnson Matthey to map the urea injection system. A description of the SCR urea injection mapping during the pilot test is provided in a technical memorandum in Appendix A-4. Figure 2-6 presents a mapping diagram of the urea injection rate designed for a 95% digester gas to natural gas fuel blend during the pilot testing period after system adjustments were made on June 8, 2010.

Source Testing Using Compliance Methods. Source testing using SCAQMD compliance methods was performed after preliminary testing of the Cat Ox/SCR system and equipment startup and commissioning in order to measure the emissions of the system. The following summarizes the source testing using compliance methods performed on April 7-8, 2010:

■ The initial testing using compliance methods was performed for one fuel blend (95% digester gas and 5% natural gas)

■ Source testing was performed to sample for CO, NOx, VOCs, ammonia, and aldehydes (formaldehyde).

■ SCAQMD Method 100.1 was used to measure NOx, CO, CO_2, and O_2 concentrations, modified CARB Method 430 was used to measure aldehydes (i.e., formaldehyde), Method 25.3 was used to measure total non-methane non-ethane organic compounds (NMNEOC), and modified SCAQMD Method 207.1 was used for measuring ammonia.

Table 2-6 describes details of the April 2010 initial test program using compliance methods.

2.4. Pilot Study Test Program Timeline

Table 2-7 presents the pilot study project timeline. The full equipment commissioning took place between March 23 and April 1, 2010. The pilot testing was conducted from April 1, 2010 through March 31, 2011. Since Engine 1 is used to provide power to the

plant, it continued operation throughout the construction and commissioning of the system, with occasional stoppages as needed by the present study as well as the J-79-1 and J-79-1A projects.

Table 2-1:
Engine 1 Design Parameters

Manufacturer:	Cooper-Bessemer
Model:	LSVB-12-SGC
Cycle:	4-stroke
Bore:	15½ in
Stroke:	22 in.
Configuration:	Vee-12
Rated Speed:	400 RPM
Rated Output:	2,500 KW
BMEP:	138 psi
Horsepower	3,471 bhp
Load	100%
Operating Hours per Year	Up to 8,760
Type of Fuel	Cleaned Digester Gas / Natural Gas
Design Exhaust Flow Rate	27,555 acfm
Design Exhaust Temperature	800°F

Table 2-2:
DGCS Design Specifications

Gas Description	Anaerobic digester gas
Flow	1440 scfm
Pressure drop per foot of media	0.5 in. w.c.
Pressure drop total with piping	7.5 in. w.c
Pressure - actual	58 psig inlet (actual)
Pressure - design	150 psig
Maximum gas inlet Temperature	70°F
Maximum Ambient Temperature	100°F
Minimum Ambient Temperature	40°F
Humidity	Saturated at 70°F
Siloxane – design	5 ppm
Siloxane – current	5 ppm
Total Reduced Sulfur (H_2S) - design	50 ppm
Total VOC – design	50 ppm
Siloxane removal	Below best available detection limit at time of testing (i.e. 100 ppbv per species using methanol impinger; or 500 ppbv per species in Tedlar® bag by GC/MS)

Table 2-3:
Comparison of DGCS Sampling Methods

Comparison of DGCS Sampling Methods	
DGCS Inlet	**Total Siloxane (ppbv)**
Tedlar® – Inlet	3,584
SUMMA Canister – Inlet	554
Methanol Impinger – Inlet	1,457

Table 2-4:
Cat Ox/SCR Performance Guarantees

Exhaust Component	Maximum Catalyst System Inlet (ppmv)	Maximum Catalyst System Outlet (ppmv)	Reduction Guarantee
NOx	50	9	82.0%
VOC	120	25	79.2%
CO	800	100	87.5%
Free Ammonia Slip	N/A	10	N/A

Notes: 1) Provided by Johnson Matthey price quotation, dated May 8, 2009.
2) N/A indicates not applicable. Ammonia was not measured before the catalyst.

Table 2-5:
Preliminary Testing Schedule

Test Run	Engine Load %	Natural Gas/Digester Gas Fuel Ratio (% NG / % DG)	Time Period (min)
1	60	50 / 50	30
2	80	50 / 50	30
3	100	50 / 50	30
4	110	50 / 50	30
5	60	100 / 0	30
6	80	100 / 0	30
7	100	100 / 0	30
8	110	100 / 0	30
9	60	5 / 95	30
10	80	5 / 95	30
11	100	5 / 95	30
12	110	5 / 95	30

Table 2-6:
Initial Pilot Study Test Program (95% Digester Gas and 5% Natural Gas)

Parameter	Reference Method	Load	No. of Tests	Sample Location
Aldehydes [1]	Modified CARB Method 430	Max.	2 2	Catalytic Oxidizer Inlet Stack Exhaust
Volume Flow	SCAQMD 1.1-4.1 EPA 19	Max. Normal Min.	1	Stack Exhaust
NO_x, CO, O_2 and CO_2	SCAQMD 100.1	Max. Normal Min.	1	Stack Exhaust
Ammonia	Modified SCAQMD 207.1	Max. Normal Min.	2	Stack Exhaust
VOCs (as NMNEOC)	SCAQMD 25.3	Max.	1	Catalytic Oxidizer Inlet SCR Outlet Stack Exhaust
NOx, CO, O_2	CEMS	N/A	N/A	Stack Exhaust
NOx, O_2	CEMS	N/A	N/A	Catalytic Oxidizer Inlet

Note: 1) Aldehydes analysis included formaldehyde, acetaldehyde, and acrolein.
2) N/A indicates not applicable.

Table 2-7:
Pilot Study Project Timeline

Action	Date
Project Construction Period	10/2009 – 3/2010
Commissioning	
■ Digester Gas Cleaning System Commissioning (AFT)	3/9/10
■ Cat Ox/SCR System Commissioning (Johnson Matthey)	3/22/10-3/31/10
Preliminary Testing/SCR Urea Injection Mapping (Johnson Matthey)	3/31/10 – 4/1/10
Pilot Study – Commence Testing	**4/1/10**
Source Testing using Compliance Methods (SCEC)	4/7/10 – 4/8/10
Urea Injection Mapping Adjustment #1 (Johnson Matthey)	5/13/10
Urea Injection Mapping Adjustment #2 (Johnson Matthey)	6/8/10
Completed Pilot Testing	3/31/11
Post-Pilot Study Testing	**4/1/11 – present**
Urea Injection Mapping Adjustment #3 (Johnson Matthey)	4/11/11 – 4/12/11

Figure 2-1: Plant 1 Engines 1, 2, and 3 (pictured left to right)

Figure 2-2: Schematic of the Pilot Testing System
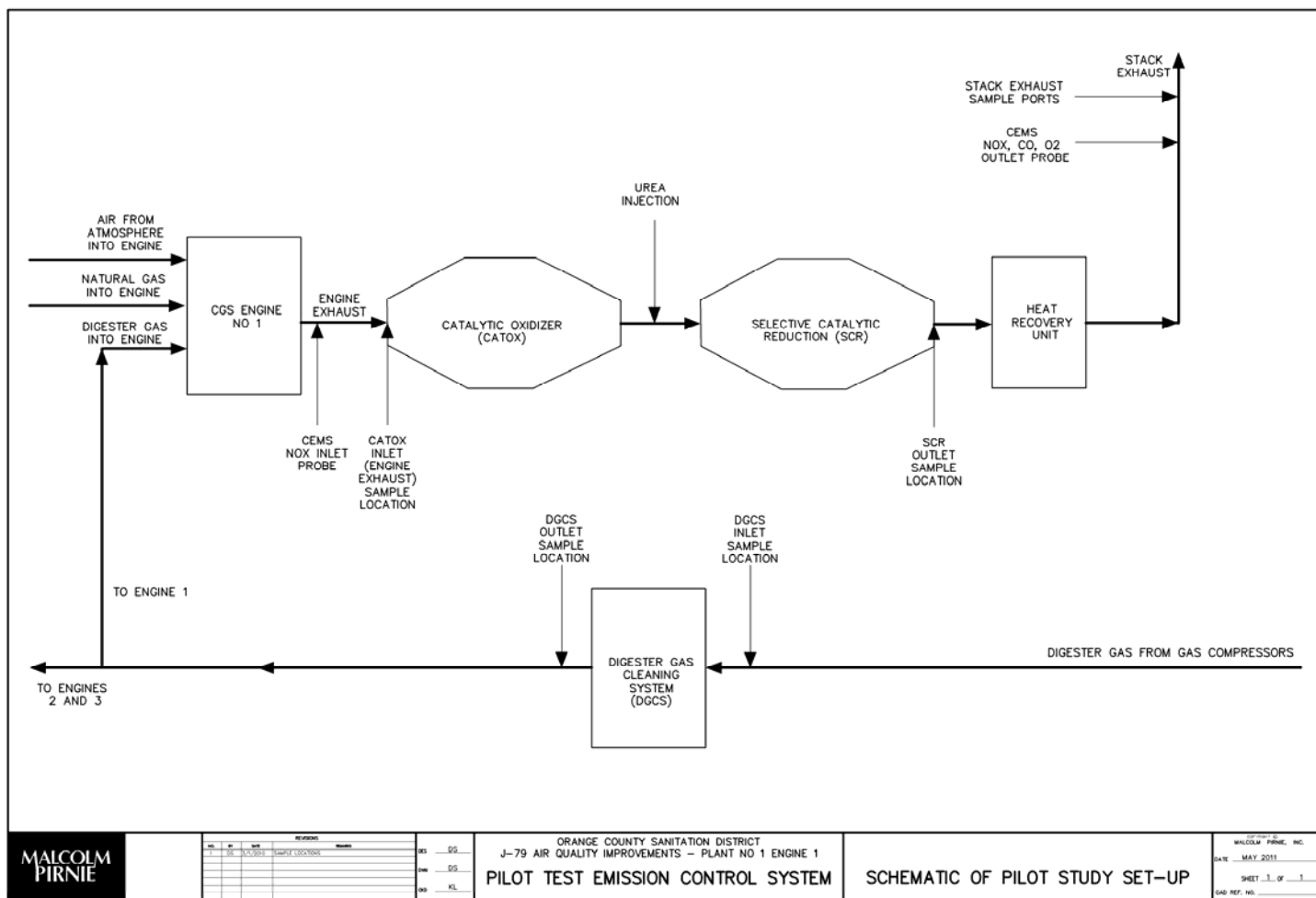
Figure 2-3: Digester Gas Cleaning System

Figure 2-4: Cat Ox/SCR Platform Installation

Figure 2-5: Catalyst and Housing
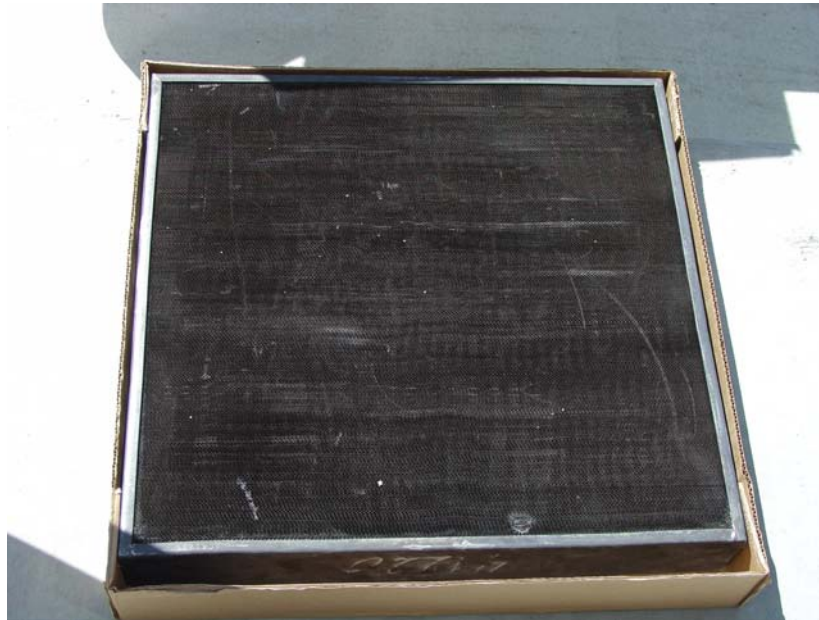
Figure 2-6: SCR Urea Injection Curve for Pilot Testing

(June 8, 2010 through March 31, 2011)
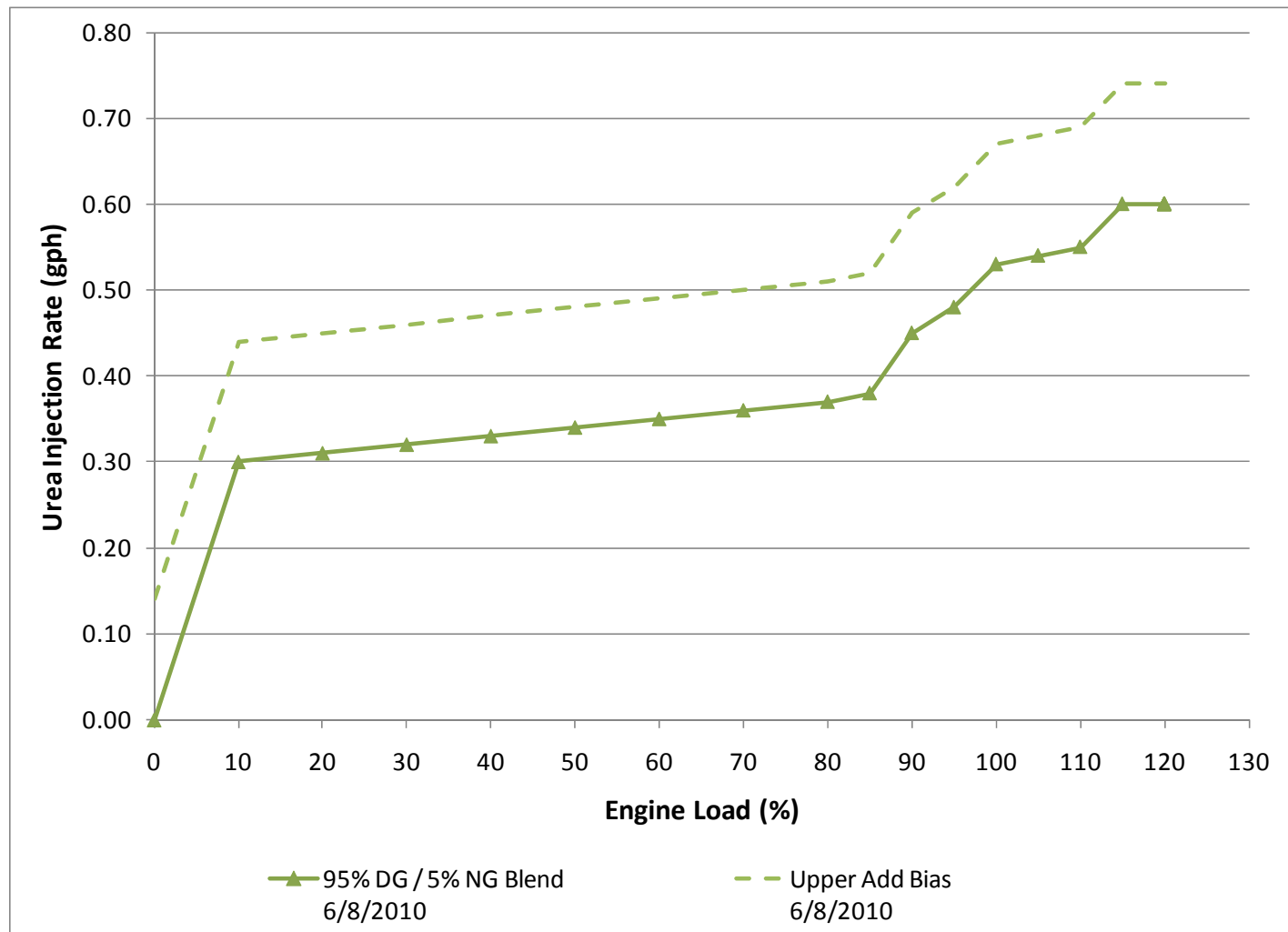
3. Results and Discussion

3.1. Digester Gas Cleaning System

The digester gas cleaning system installed at Plant 1 was designed to remove siloxanes and other impurities from the digester gas prior to being used to fuel the three IC engines. Throughout the pilot study, the performance of the DGCS system was evaluated by monitoring for carbon media performance and change out frequency. Samples for the family of siloxanes, H_2S, and speciated VOCs in the digester gas were taken at the inlet and outlet to the DGCS carbon vessel, and sent to the laboratory for testing. When the testing indicated that the DGCS media needed replacement, flow to Engine 1 was curtailed until the media was replaced. Digester gas continued to be used by Engines 2 and 3 since they were not equipped with post-combustion catalyst controls that could be fouled by the siloxanes and other contaminants in the digester gas. Once the DGCS media was replaced, the testing was resumed on Engine 1.

3.1.1. DGCS Sample Integrity

The composition of the digester gas at the inlet to the DGCS was tested for a number of compounds, including H_2S, as an indicator compound for media breakthrough, reduced sulfides, siloxanes, and a number of speciated VOCs. Since the sampling was performed using Tedlar® bags, and occasionally SUMMA canisters, the potential exists for ambient air to be captured along with the digester gas, thus diluting the sample. In order to assure that the samples were not diluted, the fixed gas composition of the gas was also measured. Fixed gases are gases for which no liquid or solid can form at the temperature of the gas, such as air at typical ambient temperatures. In the present study, N_2, O_2, CO_2, and CH_4 were the fixed gases sampled. The digester gas typically consisted of 36% carbon dioxide, 61% methane, 2% nitrogen, and less than 1% oxygen. In the event that ambient air is pulled into the digester gas sample bag, the percentage of nitrogen will be significantly greater than 2%, and the concentrations of the digester gas contaminants would be diluted.

A summary of the fixed gas composition sampling data from March 2010 through February 2011 is shown in Table 3-1. The full fixed gas composition data set is found in Appendix B-1. Over the course of this fixed gas composition sampling, three samples were eliminated due to errors in sample collection that led to a nitrogen percentage greater than 5%; one sample set (Tedlar® and Summa canister) was also eliminated due to extremely high nitrogen concentrations indicating that ambient air had leaked into the sample. However, a comparison of the inlet and outlet fixed gas composition demonstrated that the integrity of the overall digester gas samples taken was maintained with inlet and outlet concentrations of CO, CH_4, N_2, and O_2 staying within the range

expected, indicating that the carbon media did not adsorb methane or the other fixed gases.

3.1.2. Digester Gas Quality

Table 3-2 presents the results of the reduced sulfides component of the digester gas. The data indicate that H_2S is the biggest constituent of the reduced sulfides sampled. The average H_2S concentration was approximately 26 ppmv. The high H_2S input concentration makes it a good indicator compound for detecting catalyst media breakthrough at the outlet of the system. Table 3-3 presents the results of the speciated siloxane sampling. Typical of digester gases in general, D5 and D4 are the largest siloxane components of the Plant 1 digester gas. Table 3-4 presents the results of the VOC sampling. The reduced sulfide, speciated siloxane, and VOC data sets are found in Appendices B-2, B-3, and B-4, respectively.

3.1.3. DGCS Performance

The DGCS was monitored for carbon media performance and change out frequency throughout the study. Digester gas samples were taken at the inlet and outlet of the DGCS carbon vessel for total siloxane concentration and H_2S, and at the inlet for speciated siloxanes, reduced sulfides, and VOCs. Samples below the method detection level (MDL) were not used in the summary analysis.

Siloxane samples were collected using Tedlar® bags and analyzed using GC/MS at both inlet and outlet of the system. Due to the length of time required to analyze the siloxane samples (approximately several days to two weeks), H_2S sampling at the DGCS outlet using Draeger tubes was used as a real-time indicator of the DGCS carbon media performance. When H_2S was detected in the DGCS outlet above approximately 1 ppmv, Engine 1 was shut-down to prevent fouling of the catalyst material until the carbon media was replaced in the DGCS. The use of 1 ppmv H_2S as an indicator for potential media saturation is a conservative threshold selected to ensure that media breakthrough would not occur during the study. Table 3-5 presents the results of the siloxane and H_2S sampling. The table indicates that the siloxane concentrations at the inlet varied over the course of the study. As shown in Table 3-3, the average inlet concentration of total siloxanes at was approximately 5.0 ppmv. The DGCS generally removed siloxanes to below the MDL.

The carbon media was replaced three times during the pilot study: in June 2010, in September 2010, and in February 2011 after treatment of approximately 147, 174, and 157 million cubic feet of digester gas, respectively. Appendix B-5 provides a summary of reduced sulfide and speciated siloxane sampling events with DGCS carbon media use and change out frequencies. This media change-out information will be used in the cost evaluation for the overall system presented in Section 4. The effectiveness of DGCS media life may be longer than experienced during the current pilot testing because the

media change-outs were conservatively scheduled to protect the catalyst. For longer term operations, a design change to optimize media life could include the installation of two vessels in series. The second vessel would act as a polisher to provide catalyst protection from siloxane breakthrough while allowing the media in the primary vessel to be completely exhausted.

3.2. Cat Ox/SCR System

The purpose of the demonstration project testing program was to evaluate the effectiveness of the Cat Ox/SCR system for removal of CO, VOC, and NOx to comply with amended Rule 1110.2, to monitor for ammonia slip, and to evaluate the performance of the engine with the emissions control equipment installed. The pilot testing of the Cat Ox/SCR system began on April 1, 2010, immediately after completion of the SCR urea injection mapping by Johnson Matthey. The pilot study continued until March 31, 2011.

The concentrations of CO, NOx, and O_2 in the engine exhaust gas before and after the Cat Ox/SCR system were determined by an independent source testing firm using SCAQMD Method 100.1, a chemiluminescent compliance testing method, during source testing on April 7 and 8, 2010. Routine monitoring of CO, NOx, and O_2 concentrations using OCSD's TESTO 350 XL portable handheld analyzer was also performed. The use of the portable analyzer measuring CO and NOx allowed for numerous data sets to be collected at regular intervals throughout the pilot study. The detailed portable analyzer test report can be found in Appendix C-1. In addition, a CEMS monitored and recorded the 15-minute block average NOx concentrations at the catalytic oxidizer inlet (engine exhaust) and the NOx, CO and O_2 concentrations at the stack exhaust. VOC concentrations were measured periodically at the engine exhaust and stack exhaust using SCAQMD Method 25.3.

The results of the source testing at Plant 1 using SCAQMD compliance methods on April 7-8, 2010 and SCAQMD Rule 1110.2 compliance testing in January 2011 are shown in Tables 3-6 and 3-7, respectively. Results for the January 2011 source testing at Plant 1 in Table 3-7 are also shown for Engines 2 and 3 for comparison. As shown in the January 2011 annual compliance test results (Table 3-7), the average NOx and CO concentrations in Plant 1 Engine 1 over three loads are 6.2 and 7.9 ppmv, respectively. This is lower than the average Engines 2 and 3 NOx and CO concentrations over three loads of 30.2 and 390.5, respectively. Results of the routine pilot test sampling events are provided in Section 3.3.

3.3. Compliance with Future Rule 1110.2 Emission Limits

The results of the pilot study were evaluated for compliance with the future Rule 1110.2 emission limits. The CO and VOC results represent data collected after the initial startup of the equipment from April 1, 2010 through March 31, 2011. The NOx results represent

data collected after the urea injection system was optimized on June 8, 2010 through March 31, 2011.

3.3.1. Carbon Monoxide Concentration

CO concentration data were collected during source testing at the engine exhaust and stack exhaust routinely throughout the pilot testing period using the hand-held portable analyzer at the engine exhaust and SCR outlet and also continuously at the stack exhaust by the CEMS. The data collected during these events is summarized in Table 3-8. All CO data collected by the portable analyzer and the CEMS are presented in Appendices C-1 and C-3, respectively.

The CO concentration data at the engine exhaust (CO inlet) and the stack exhaust (CO outlet) are presented graphically in Figure 3-1. The CO inlet concentration was measured with the portable analyzer. The CO outlet concentration, measured by the CEMS, is shown as the maximum daily 15-minute average CO outlet concentration. The percent reduction in CO concentration measured across the Cat Ox/SCR system by the portable analyzer consistently exceeded 96% reduction. This performance was consistent when firing either digester or natural gas. This CO concentration removal rate exceeds the expected performance based upon the catalytic oxidizer vendor guarantee of 87.5% CO removal, provided in Table 2-4.

3.3.2. Volatile Organic Compounds Concentration

The VOC concentration data in terms of NMNEOC was collected during source testing at the engine exhaust, the stack exhaust, and routinely throughout the pilot testing period using SCAQMD Method 25.3. All data collected is presented in Appendix C-2. As shown in Table 3-9, the average VOC concentration at the stack exhaust was 3.58 ppmv, below the emission limit of 30 ppmv in the future Rule 1110.2.

Data measured during the pilot testing period were compared to VOC concentrations measured for the OCSD Rule 1110.2 Annual Permit Compliance Test Report for Year 2011. Table 3-7 summarizes the annual permit compliance VOC test results for OCSD Plant No. 1.

The average uncontrolled VOC concentration for Engines 2 and 3 during the compliance testing was 97 ppmv, while the controlled VOC concentration from Engine 1 stack exhaust was 3.24 ppmv. This is in the same range of the VOC concentrations measured during the pilot testing period (i.e., 3.58 ppmv), confirming the effectiveness of the catalytic oxidizer (at approximately 96%) in removing VOCs from the engine exhaust.

It should be noted that the stack exhaust VOC concentrations for Engines 2 and 3 of 97.2 and 96.9 ppmv, respectively, are much higher than the VOC concentrations measured at the Engine 1 engine exhaust during the pilot testing period, which averaged 21.84 ppmv

(refer to Appendix C-2). One possible explanation to this is the arrangement of the Engine 1 sampling port before the catalytic oxidizer. Typically, when sampling using SCAQMD Method 25.3, two samples are gathered from two separate probes and the results of the analyses are averaged. In the case of this pilot study, the valve at the engine exhaust sampling port was not large enough to locate two adjacent probes, and it was not possible to expand the sampling port. Therefore, the sample and duplicate sample were not taken at the same time, but one after the other. The VOC data collected at the engine exhaust represents the higher of the two sample data results, in line with SCAQMD's general mandate that the higher value be reported when the results differ by more than 20%. Despite the lower accuracy in the engine exhaust sample due to the sizing of the sampling port, the sample taken at the stack exhaust location met the SCAQMD accuracy criteria.

3.3.3. Nitrogen Oxides Concentration

NOx concentration data were collected during source testing at the engine exhaust and stack exhaust, routinely throughout the pilot testing period using the portable hand-held analyzer at the engine exhaust, after the catalytic oxidizer and stack exhaust; and continuously at the engine exhaust and stack exhaust by the CEMS.

Based on the results of previous source testing, it is observed that the concentration of NOx produced in the engine exhaust for a given load is higher when firing natural gas than when firing digester gas at any given load. Therefore, the efficiency of the SCR system is reduced as the percentage of natural gas increases. The original urea injection set points, set on April 1, 2010 during commissioning, were set for a blend of digester gas and natural gas. The set points, which are a function of engine load, were adjusted on June 8, 2010 to decrease urea flow because a higher ratio of digester gas to natural gas was fired in Engine 1 than was originally anticipated. Therefore, the urea injection rates were reduced to control a lesser concentration of NOx in the exhaust gas. The data presented in this section represents the pilot testing period from June 8, 2010 through March 31, 2011. The data collected during this period are summarized in Table 3-10. The entire dataset collected is presented in Appendix C-3.

The NOx concentration data at the engine exhaust and the stack exhaust measured by the CEMS are presented graphically in Figure 3-2. The NOx inlet and outlet concentration is shown as the daily maximum 15-minute average NOx concentration. The percentage reduction in NOx concentration measured across the Cat Ox/SCR system by the portable analyzer ranged from 76 to 98%. This NOx concentration removal rate is close to the expected performance based upon the Cat Ox/SCR vendor guarantee of 82% NOx removal. A review of the NOx concentration data over the period of the pilot study indicates that the performance of the SCR is affected both by the ratio of digester to natural gas used as fuel in the engine, and by the system's responsiveness to engine operating parameters, such as start-up and differing load conditions. The inability of the

SCR system to meet the vendor guarantee may be due to periods of increased natural gas flow in the fuel gas. This was to be expected because the urea injection system was mapped for a primarily digester gas (greater than 95 percent) fuel blend. The control system can only be set with one set of engine load to urea injection set points and is not designed to change urea injection rates depending on the fuel blend. Johnson Matthey has not designed a control system that can accommodate varying loads and fuel blends. Therefore, during periods when the fuel is supplemented by natural gas, the NOx removal efficiency is expected to be reduced. If the set points were adjusted for a natural gas fuel usage, which is atypical, the system may over-inject urea potentially causing an ammonia slip as discussed below.

3.3.3.1.   NOx Concentrations Above Rule 1110.2 Limit

During the pilot testing period, the NOx outlet concentration occasionally spiked above the future Rule 1110.2 limit of 11 ppmv. NOx concentrations are measured continuously by the CEMS system and averaged in 15-minute blocks for compliance purposes. For the purposes of this Report, each 15-minute block is defined as a "period". A "high NOx outlet event" is defined as one period or multiple periods in a short time span where the NOx outlet concentration exceeds 11 ppmv. The NOx outlet concentration exceeded 11 ppmv for a total of 97 high NOx outlet events (940 periods out of 21,285 periods of engine operating time) during the pilot test.

Many of the high NOx outlet events were removed from the data set when evaluating performance of the SCR system. A majority of the spikes in NOx outlet concentration correlated with high NOx outlet events when: 1) the engine had just come online, 2) there was an increase in the percentage of natural gas in the engine fuel blend, 3) engine loads exceeded the loads mapped during the initial urea injection rate programming, and 4) operational adjustments of the Cat Ox/SCR system took place. Once excursions over 11 ppmv were screened for exempt or non-valid conditions such as engine start-up and non-control system error, 181 15-minute periods out of 21,285 periods of operating time (less than 0.9% of the total measurement periods during the pilot study) remained above 11 ppmv. The lowest NOx stack exhaust concentration met consistently under all valid conditions was 16 ppmv. Table 3-11 presents a break-down of the number of high NOx outlet events and periods when the NOx outlet concentration at the stack exhaust exceeded 11 ppmv.

Exempt or Non-Valid Periods. A total of 7 high NOx outlet events (703 periods or 3.3% of the total engine operating period) were during times when operational issues and system adjustments caused the NOx to exceed 11 ppmv. These events included urea injection system adjustments by the system vendor, operation of the SCR system without urea in the storage tank, modifications to the engine automation system, improper operation of the SCR system, and clogging in the urea injection lance. These periods

were removed from the stack exhaust NOx data set because they do not represent proper operating conditions of the SCR system.

During the pilot testing period, 29 high NOx outlet events (56 periods or 0.3% of the total engine operating time) were classified as occurring during engine start-up. Rule 1110.2(h)(10) allows for an exemption during engine start-up to allow for sufficient operating temperatures to be reached for proper operation of the emission control equipment. The start-up period is limited to 30 minutes unless a longer period is approved for a specific engine by the Executive Officer and is made a condition of the engine permit. Periods where NOx outlet concentrations exceeded 11 ppmv within 30 minutes of engine start-up were removed from the data set for evaluation of the SCR system performance.

Validated Periods. A number of the remaining high NOx outlet events could be attributed to periods during which the engine was operating with natural gas fuel or at a load that exceeded the range that was originally mapped into the urea injection system. The urea injection system was programmed assuming a fuel blend of 95% digester gas to 5% natural gas. An event was attributed to a rise in natural gas usage if the fuel blend decreased to below 95% digester gas during the same period or during the period immediately preceding the event. A total of 17 high NOx outlet events (43 periods or 0.2% of total engine operating time) occurred when the fuel blend decreased to below 95% digester gas. It was observed that the production of NOx at the engine exhaust increased as the percentage of natural gas in the engine fuel increased. Therefore, as the digester gas to natural gas fuel ratio decreased to below 95% digester gas (i.e., using more natural gas in the fuel blend), the urea injection system would not inject a sufficient quantity of urea to compensate for the additional NOx being produced and NOx outlet concentration would increase.

A total of 22 high NOx outlet events (63 periods or 0.3% of the total engine operating time) occurred when the engine load exceeded 100%. During the pilot testing period, the urea injection rate setpoints were set for an engine load range of 0% to 100%. An event was considered to be due to an increase in engine load if the engine load increased to above 100% during the same period or during the period immediately preceding the event. When the engine load exceeded 100% of design load for an extended period of time, the urea injection rate was not able to adjust properly because the engine operation surpassed the programming of the system.

There are 22 high NOx outlet events (75 periods or 0.4% of the total engine operating time) that could not be attributed to operational issues/system adjustments, engine start-up, increased natural gas fuel usage, or high engine load. The NOx outlet concentrations during the majority of these periods typically ranged between 11 and 12 ppmv, with a maximum of 16 ppmv.

The maximum NOx concentration at the outlet was 16 ppmv after removing the non-control system related exceedances, including operational issues/system adjustments and engine start-up. The validated average, minimum, and maximum NOx outlet concentrations recorded by the CEMS are presented in Table 3-12. The validated data set includes the NOx outlet concentration data during increased natural gas fuel usage, high engine load, and other high NOx outlet events not attributed to operational issues/system adjustments, engine start-up, increased natural gas fuel usage, or high engine load. Following the pilot test, the urea injection setpoints and biases may be increased to account for increased NOx production due to increased natural gas in the fuel blend and higher engine loads. Increasing the urea injection setpoints may also reduce the number of other high NOx outlet events that fall just above the 11 ppmv NOx limit.

In April 2011, after the official pilot testing period concluded, a Johnson Matthey technician adjusted the urea injection rate curve to 1) expand the curve to a maximum of 125% engine load and 2) to increase the urea injection rate at high engine loads. The increase in urea injection rate should accommodate for the increased NOx production when the engine incorporates more natural gas into the fuel blend. Further observation will be required to confirm if these adjustments will lead to a reduction in the number of periods where stack exhaust NOx outlet concentration exceeds 11 ppmv.

3.3.4. Ammonia Concentration

The SCR system reduces NOx through a chemical reaction between ammonia and NOx, facilitated by a catalyst to form nitrogen and water vapor. Once urea is injected into the engine exhaust stream, it breaks down into ammonia and other constituents. Hydrolysis of the urea on the face of the catalyst generates more ammonia. While NOx reduction is the goal of the SCR system through the consumption of the ammonia, injection of too much urea can result in excess ammonia (total ammonia) at the SCR outlet in the form of free ammonia (NH_3), and/or other ammonia-formed compounds. Parts of the total ammonia can then participate in secondary reactions with other compounds in the exhaust gas forming by-products, such as ammonium sulfates (combined ammonia). These secondary ammonia by-products may have the undesirable potential to increase maintenance requirements on the equipment downstream from the SCR, due to clogging and particulate buildup. The remaining gaseous ammonia (free ammonia) that is emitted at the stack exhaust is referred to as ammonia slip. SCAQMD regulated the amount of ammonia slip in the Pilot Study Research Permit not to exceed 10 ppmv of free ammonia at the stack exhaust.

Three methods were used for determining ammonia concentration:

■ On-site field measurement of free ammonia using Draeger® or Sensidyne® tubes,

■ Modified SCAQMD Method 207.1 to measure free ammonia, and

- Estimated total ammonia concentration (free plus combined ammonia) calculation method using inlet and outlet NOx CEMS concentrations and the urea injection rate.

Free ammonia concentration data was collected during source testing at the stack exhaust using modified SCAQMD Method 207.1, and also routinely monitored throughout the pilot testing period using Draeger® tubes or Sensidyne® tubes at the SCR outlet. Both tests provide concentration data for free ammonia. Total ammonia was also calculated from the CEMS data based on the NOx inlet and outlet concentrations and the urea injection rate. The limitations of this total ammonia calculation are discussed in detail in a technical memorandum *OCSD Cat Ox/SCR Pilot Study: Ammonia Sampling and Calculation Methods* (Malcolm Pirnie, May 2011) found in Appendix C-2. As with the NOx data, the ammonia data presented in this section represents data collected during the pilot testing in the period from June 8, 2010 through March 31, 2011, after the urea injection rate set points were adjusted on June 8, 2010. Figure 3-3 presents the maximum total ammonia estimate for each day of the pilot test between these dates using the calculation method.

Over the course of the pilot testing period, the Draeger® tubes consistently measured free ammonia concentrations at the stack exhaust below MDL. During the same time period when the ammonia field measurements were taken, the calculated total ammonia concentration using the 15-minute block averages reported by the CEMS had a value ranging from 0 to 5 ppm of ammonia.

Estimated Total Ammonia Calculation. The calculation method for total ammonia is dependent on the NOx inlet and NOx outlet concentrations and the urea injection rate, which is continuously adjusting based on the engine load and the NOx outlet concentration. The ammonia calculation equation is shown below, where CF can be used as a correction factor to account for factors such as secondary reactions and limitations of the urea injection system, and as a tool to adjust the calculation of total ammonia to estimate free ammonia.

$$NH_3 = [Urea\ Fed – (NOx\ in – NOx\ out)\ /2]\ x\ CF$$

The CF was assumed to be equal to 1 in the present study. Throughout the pilot testing, differences were observed between the free ammonia measured in the field and total ammonia estimated using the calculation method. The calculation method assumes that the ammonia/NOx reaction is the only reaction consuming the urea. There is the potential for ammonia molecules to be consumed in other secondary reactions in the exhaust stream, such as those with sulfur compounds. Sulfur dioxide (SO_2) and sulfur trioxide (SO_3) can react with ammonia to produce ammonium sulfate (NH_4HSO_4) and ammonia bisulfate (ammonia hydrogen sulfate) (($NH_4)_2SO_4$) which can precipitate out of the exhaust gas at low temperatures (300-450°F) as ammonium salts (combined ammonia). Ammonium salts have the potential to deposit on equipment downstream from

the SCR catalyst, such as the heat recovery boiler, reducing their efficiency and increasing maintenance requirements. Field measurements during the pilot test were only performed for free ammonia which did not include ammonia compounds, such as the ammonium salts. Low ammonia concentration Draeger® tube measurements combined with the and high exhaust gas temperatures ($\sim 800^\circ F$) taken directly after the SCR catalyst indicate that the potential for these secondary reactions is low.

Engine load fluctuates with time. When the IC engines are set to a base load, it was observed that the actual engine load fluctuated rapidly by as much as ten percent below the set point. This was found to be typical for the OCSD IC engines. However, since urea injection rate is mapped to engine load, the rapid fluctuations in load can result in rapid changes in urea injection rates. Rapidly changing urea injection rates, instead of steady rates with smooth transitions, can cause inaccuracies in the ammonia calculation.

SCAQMD Sampling Using Compliance Methods. Free ammonia was measured at the stack exhaust once during the initial source testing event from April 7-8, 2010, and once after the pilot testing period on May 10, 2011. On both occasions, ammonia slip concentrations at three engine loads measured by Modified SCAQMD Method 207.1 were found to be less than 0.5 ppmv. Neither the Draeger® tube nor Sensidyne® tube free ammonia measurements at the SCR exhaust were above the MDL. However, the total ammonia estimate based on the theoretical calculation using the CEMS data was three to ten times higher than the measured value using the compliance method. Results of these sampling events are compared in Table 3-13.

Further sampling of the exhaust emissions can be performed to establish a value for the correction factor, CF, in the estimated total ammonia calculation method for the calculation of free ammonia. If found, the presence of sulfur dioxide and sulfur trioxide in the exhaust gas before the SCR, and ammonium sulfate and ammonia bisulfate, in the exhaust gas after the SCR, can indicate secondary reactions taking place due to the injection of urea. In addition, inspection of the heat recovery boiler during the next scheduled maintenance may also indicate the presence of ammonium salts in the exhaust gas. A correction factor can be applied to the estimated total ammonia calculation to account for these secondary reactions, thus allowing for the estimation of free ammonia. If ammonium salts are identified in the heat recovery boiler, adjustments to the urea injection rates or additional maintenance of the heat recovery boiler may be required.

Compliance monitoring for free ammonia is more accurate when reflective of gaseous ammonia emitted from the stack, while the estimated total ammonia calculation method may reflect both free ammonia and ammonia by-products produced in the exhaust gas. Although the pilot study data indicates that there is minimal, if any, free ammonia (ammonia slip) due to the SCR system, it is recommended that the OCSD perform

additional and routine testing for ammonia slip during varying loads and fuel blends over a period of time.

3.4. Engine Performance

A significant amount of operational data was collected throughout the pilot test. The data logger installed within the urea injection control cabinet collected additional data beyond that collected by the CEMS. These data included the temperature at the catalytic oxidizer inlet and outlet, and the SCR inlet and outlet and the differential pressure across the catalytic oxidizer and SCR catalysts. The system urea injection and back pressure performance proposed by Johnson Matthey is provided in Table 3-14. The data collected by the data logger are summarized in Table 3-15 and were validated to remove periods when the engine was offline. Periods when the engine was offline were identified as those periods when the urea injection is offline, when the temperatures in the catalyst housings cool and the NOx inlet concentration decreases to zero.

During the pilot test, there were no notable back pressure effects on engine performance due to the installation of the Cat Ox/SCR system with a digester gas cleaning system. The engine manufacturer's allowable back pressure is 20 inches of water column (in. wc.). The engineering design estimate of the maximum engine exhaust system back pressure without the Cat Ox/SCR system was 11 in. wc. Therefore, the available system design back pressure for the Cat Ox/SCR system and additional exhaust ductwork was 9 in. wc. Based on the data provided by the data logger in during the pilot test, the average differential pressure through the catalytic oxidizer and SCR are approximately 0.3 and 1.0 in. wc., respectively. Therefore, it is concluded that the system does not negatively affect engine performance.

The exhaust gas temperature reported through the catalytic oxidizer and SCR and the urea injection rate indicate proper system performance. The average inlet and outlet temperature through both catalysts is between 750°F and 800°F, which is in the proper temperature range for ammonia to react in the SCR catalyst. The actual urea injection rate of approximately 0.6 gallons per hour (gph) is also below the urea usage estimate of 1.1 gph proposed by Johnson Matthey.

The DGCS has had a positive effect on engine performance. The use of cleaned digester gas at Plant 2 Engine 3 resulted in much less frequent maintenance requirements for the engine, including longer time intervals between spark plug changes and major maintenance events. OCSD Operations continues to use the DGCS from the 2007 pilot study at Plant 2 Engine 3 after improvements in performance of the engine and maintenance cost savings resulted from use of the DGCS. These savings are discussed further in Section 4.

3.5. Summary of System Results

The overall results of the pilot study are:

■ The maximum NOx concentration at the stack exhaust after the pilot study controls was approximated 16 ppmv, and the average NOx concentration was approximately 7.2 ppmv, below the 11 ppmv required under amended Rule 1110.2. Further adjustment of the urea injection rate was performed after the end of the pilot study, and these new data will be evaluated further to determine if this urea injection rate modification will eliminate excursions above 11 ppmv.

■ While there were some excursions above 11 ppmv, once these excursions were screened for exempt conditions like start-up, and non-control system error, less than 0.9% of the total measurement periods during the pilot study, or 181 15-minute periods out of 21,285 periods in total remained above 11 ppmv.

■ Using monitoring data for gaseous free ammonia collected using the SCAQMD method and Draeger® tube method, the free ammonia concentration was below 0.5 ppmv and MDL over the pilot study, respectively.

■ Based on the calculation method for total ammonia, the maximum total ammonia concentration during ammonia concentration sampling events was estimated to be 4.65 ppmv. It is believed that this is an overestimate due to limitations of the calculation, such as not accounting for potential secondary ammonia reactions. Despite this, the estimated total ammonia calculation method can be used as a tool to prompt a field measurement to determine free ammonia (ammonia slip) with the application of an appropriate correction factor, CF. Further evaluation needs to be performed to develop a correction factor that will correlate the calculation method and the measured values of free ammonia.

■ The percentage reduction in CO concentration measured across the Cat Ox/SCR system by the portable analyzer ranges consistently exceeded a 96% reduction in CO concentration from the engine exhaust.

■ The maximum CO concentration at the stack exhaust using the CEMS data was 42.2 ppmv, well below the amended Rule 1110.2 emission limit of 250 ppmv.

■ The catalytic oxidizer was found to result in removing approximately 96 % VOCs from the engine exhaust.

■ The maximum VOC concentration at the stack exhaust was found to be 5.42 ppmv using Method 25.3, and consistently well below the 30 ppmv in amended Rule 1110.2.

- The DGCS system, in general, removed siloxanes from the digester gas to below MDL levels and significantly reduced sulfur compounds and VOCs successfully reducing catalyst masking which should lead to extended catalyst life.

- The DGCS system resulted in overall improvements in engine maintenance requirements.

- No back pressure concerns for the engine due to the additional equipment were identified.

Table 3-1:
Summary of Fixed Gases in Plant 1 Digester Gas

Fixed Gas	DGCS Inlet			DGCS Outlet		
	Min.	Max.	Avg.	Min.	Max.	Avg.
	(%)	(%)	(%)	(%)	(%)	(%)
Carbon Dioxide (CO_2)	25.5	40.1	33.9	23.1	37.2	32.8
Methane (CH_4)	53.7	62.6	58.7	45.0	62.5	58.0
Nitrogen (N_2)	0.9	5.1	2.2	1.1	1.9	1.5
Oxygen (O_2)	0.1	1.4	0.6	0.1	0.8	0.4

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Table 3-2:
Summary of Reduced Sulfides in Plant 1 Digester Gas

Compound	DGCS Inlet		
	Min.	**Max.**	**Avg.**
	(ppmv)	**(ppmv)**	**(ppmv)**
Hydrogen Sulfide	14.7	31.9	26.4
Carbonyl Sulfide	0.01	0.03	0.02
Methyl Mercaptan	0.05	0.08	0.06
Ethyl Mercaptan	0.2	0.3	0.3
Dimethyl Sulfide	0.006	0.02	0.01
Carbon Disulfide	0.004	0.009	0.006
n-Propyl Thiol	0.5	0.8	0.6
iso-Propyl Thiol	0.2	0.4	0.3
Dimethyl Disulfide	ND	ND	ND
Isopropyl Mercaptan	0.3	0.3	0.3
n-Propyl Mercaptan	0.3	0.3	0.3

Note: 1) ND indicates non-detect.

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Table 3-3:
Summary of Speciated Siloxanes in Plant 1 Digester Gas

Compound	DGCS Inlet		
	Min.	Max.	Avg.
	(ppbv)	(ppbv)	(ppbv)
Hexamethyldisiloxane (L2)	<MDL	<MDL	<MDL
Hexamethylcyclotrisiloxane (D3)	10	17	12
Octamethyltrisiloxane (L3)	10	19	14
Octamethylcyclotetrasiloxane (D4)	369	1,600	704
Decamethyltetrasiloxane (L4)	73	170	121
Decamethylcyclopentasiloxane (D5)	1,300	14,000	5,371
Total Siloxanes	919	15,700	5,452

Note: MDL is mean detection level.

Table 3-4:
Summary of Speciated VOCs in Plant 1 Digester Gas

| Analyte | DGCS Inlet | | |
| | Min. | Max. | Avg. |
	(ppbv)	(ppbv)	(ppbv)
Acetone	7.0	88.0	26.0
Benzene	7.3	15.7	10.7
Chlorobenzene	4.5	6.4	5.4
Cyclohexane	4.9	22.0	13.6
1,4-Dichlorobenzene	5.0	28.0	16.4
cis-1,2-Dichloroethene	17.2	103.0	41.4
trans-1,2-Dichloroethene	4.6	4.6	4.6
Ethyl Acetate	22.2	22.2	22.2
Ethylbenzene	37.0	141.0	74.2
4-Ethyltoluene	12.7	68.6	33.7
Freon 11	5.2	6.3	5.8
n-Heptane	57.8	122.0	84.2
Hexane	27.0	210.0	76.5
Methylene Chloride	5.2	14.0	8.9
Methyl Isobutyl Ketone (MIBK)	4.4	4.5	4.4
Propene	2,410	3,730	3,226
Styrene	4.2	24.7	10.7
Tetrachloroethene (PCE)	11.0	11.0	11.0
Tetrachloroethylene	6.0	26.3	13.5
Toluene	1,090	7,300	2,296
1,2,4-Trichlorobenzene	9.2	9.2	9.2
Trichloroethene (TCE)	9.6	28.0	15.8
Trichloroethylene	6.2	22.9	11.7
1,2,4-Trimethylbenzene	67.1	240.0	123.1
1,3,5-Trimethylbenzene	30.0	88.0	45.8
2,2,4-Trimethylpentane	27.0	66.0	52.0
m & p-Xylene	47.0	180.0	96.1
o-Xylene	20.0	64.0	36.3
Total VOCs	**1,594**	**11,133**	**4,927**

Table 3-5:
Summary of Siloxane and H₂S Sampling

Date of Sampling	Approximate Volume of Gas Treated (million cubic feet)	Total Siloxane		H₂S			
				SCAQMD 307-91		Draeger Tube	
		Inlet	Outlet	Inlet	Outlet	Inlet	Outlet
		(ppmv)	(ppmv)	(ppmv)	(ppmv)	(ppmv)	(ppmv)
3/16/2010	0.00	3.58	<MDL	N/A	N/A	N/A	N/A
4/7/2010	27.26	8.51	<MDL	N/A	N/A	N/A	N/A
4/21/2010	53.41	N/A	N/A	25.70	ND	26	ND
4/29/2010	68.93	15.70	ND	N/A	N/A	N/A	N/A
5/11/2010	91.86	N/A	N/A	31.70	0.263	31	ND
5/27/2010	122.58	2.67	0.015	N/A	N/A	N/A	N/A
6/8/2010	144.70	N/A	N/A	27.97	2.162	30	2
6/11/2010	146.46	8.49	0.248	N/A	N/A	N/A	N/A
6/12/2010	Carbon media changed.						
6/22/2010	18.44	N/A	N/A	21.62	ND	27	N/A
6/29/2010	32.70	8.69	N/A	N/A	N/A	N/A	N/A
7/7/2010	46.34	N/A	N/A	28.57	ND	25	N/A
7/21/2010	68.89	N/A	N/A	24.87	ND	25	N/A
8/3/2010	90.04	N/A	N/A	27.45	ND	25	N/A
8/12/2010	106.00	N/A	N/A	28.19	ND	26	N/A
8/12/2010	106.00	3.73	ND	N/A	N/A	N/A	N/A
9/1/2010	137.15	4.57	<MDL	N/A	N/A	N/A	N/A
9/1/2010	137.15	N/A	N/A	14.69	ND	14	N/A
9/14/2010	162.45	N/A	N/A	23.01	0.545	23	N/A
9/15/2010	164.63	4.35	<MDL	N/A	N/A	N/A	N/A
9/17/2010	168.63	N/A	N/A	N/A	N/A	N/A	2.5
9/20/2010	173.62	5.73	<MDL	N/A	N/A	N/A	N/A
9/21/2010	Carbon media changed.						
11/4/2010	43.40	5.23	N/A	N/A	N/A	N/A	N/A
1/12/2011	114.53	6.55	N/A	N/A	N/A	N/A	N/A
1/25/2011	137.78	N/A	N/A	28.54	ND	27	N/A
2/9/2011	156.47	N/A	N/A	31.87	1.755	30	N/A
2/9/2011	156.47	4.58	<MDL	N/A	N/A	N/A	N/A
2/14/2011	Carbon media changed.						
2/23/2011	17.72	N/A	N/A	24.46	ND	25	N/A
2/24/2011	20.09	6.64	N/A	N/A	N/A	N/A	N/A

Notes: 1) All samples are taken using Tedlar® bags, except where otherwise noted as using Draeger® tubes for H₂S.

2) Inlet and outlet sample results from 5/19/10 are not accurate due to an error in collection, indicated by high nitrogen composition (>5%), and are not included in the minimum, maximum and average.

3) Outlet sample results from 6/29/10 are not accurate due to an error in collection, indicated by high nitrogen composition (>5%), and are not included in the minimum, maximum and average.

4) Inlet and outlet sample results from AccuLabs on 8/12/10 are not accurate due to an error in collection, indicated by high nitrogen composition (>5%), and are not included in the minimum, maximum and average.

5) Sample results from 8/19/10 are not consistent with sample results from other laboratories and are concluded to be erroneous and not included in the minimum, maximum and average.

6) N/A indicates that the compound was not analyzed.

7) ND indicates non-detect.

8) <MDL indicates less than the Method Detection Limit.

Table 3-6:
Plant 1 Engine 1 April 7-8, 2010 Testing using SCAQMD Compliance Methods

Parameter	Units	Low Load	Normal Load	High Load	Average Load
Load	KW	1,598	2,303.5	2,515.8	2,139.1
	%	65	90	105	86.7
Volume Flow	dscfm	5,662	8,423	9,244	7,776.3
Fuel Flow	NG scfm	14.2	19.7	20.8	18.2
	DG scfm	470.7	635.3	688.8	598.3
Stack Exhaust					
NOx	ppm	6.5	4.7	8.5	6.6
CO	ppm	7.3	4.9	4.9	5.7
TGNMNEO	ppm	N/A	N/A	2.6	2.6
Formaldehyde	ppm	N/A	N/A	0.434	N/A
Acetaldehyde	ppm	N/A	N/A	0.023	N/A
Acrolein	ppm	N/A	N/A	< MDL	N/A
Ammonia	ppm	0.12	0.18	0.43	0.2
O_2	%	10.59	11.97	12.03	11.5
CO_2	%	8.56	7.55	7.69	7.9
Engine Exhaust					
TGNMNEO	ppm	N/A	N/A	25.86	N/A
Formaldehyde	ppm	N/A	N/A	21.44	N/A
Acetaldehyde	ppm	N/A	N/A	0.419	N/A
Acrolein	ppm	0.18	0.18	< MDL	N/A

Notes:　1) N/A indicates not applicable.

2) <MDL indicates less than the Method Detection Limit.

Table 3-7:
SCAQMD Rule 1110.2 Year 2011 Permit Compliance Test Report

Parameter	Units	Low Load	Normal Load	High Load	Average Load
Engine 1					
Load	KW	1,655	1,929	2,438	2,183.5
	%	66	77	98	87.3
Volume Flow	dscfm	6,194	7,406	9,124	8,265.0
NOx	ppm	4.6	5.4	6.9	6.2
CO	ppm	6.2	7.6	8.2	7.9
TGNMNEO	ppm	N/A	3.2	N/A	N/A
PM	gr/dscf	N/A	0.0	N/A	N/A
O_2	%	10.90	11.84	12.16	12.00
CO_2	%	8.59	7.83	7.52	7.68
Engine 2					
Load	KW	1,618	1,852	2,455	2,153.7
	%	65	74	98	86.2
Volume Flow	dscfm	6,513	7,598	9,867	8,732.5
NOx	ppm	27.8	27.6	31.6	29.6
CO	ppm	348.7	390.4	432.3	411.4
TGNMNEO	ppm	N/A	97.2	N/A	N/A
PM	gr/dscf	N/A	0.0010	N/A	N/A
O_2	%	11.79	12.04	12.53	12.29
CO_2	%	7.80	7.60	7.16	7.38
Engine 3					
Load	KW	1,748	1,981	2,488	2,234.6
	%	70	79	100	89.4
Volume Flow	dscfm	6,703	7,746	9,652	8,699.0
NOx	ppm	29.1	30.1	31.2	30.7
CO	ppm	317.3	343.8	394.7	369.3
TGNMNEO	ppm	N/A	96.9	N/A	N/A
PM	gr/dscf	N/A	0.0049	N/A	N/A
O_2	%	11.68	12.01	12.49	12.25
CO_2	%	7.87	7.57	7.18	

Notes: 1) N/A indicates not applicable

Table 3-8:
Summary of CO Concentrations from Inlet and Outlet of Cat Ox/SCR System

Sampling Method	Catalytic Oxidizer Inlet Concentration (ppmvd) [1]			SCR Outlet/Stack Exhaust Concentration (ppmvd) [1]		
	Min.	Max.	Avg.	Min.	Max.	Avg.
Portable Analyzer[2]	367.5	598.7	451.6	<MDL	17.2	5.8
CEMS [3]	N/A[4]	N/A[4]	N/A[4]	4.0	42.2	7.5

Notes: 1) Concentrations are presented in parts per million by volume dry (ppmvd) at 15% O_2
2) CO concentrations by portable analyzer are measured routinely starting on April 7, 2010, after initial mapping of the SCR system.
3) NOx and CO CEMS data is based on an average of the 15-minute average NOx and CO concentrations for each calendar day. .
4) N/A: CEMS measures CO at the stack exhaust only; therefore, there is no CEMS data at the Cat Ox inlet.

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Table 3-9:
VOC Concentrations at Stack Exhaust

Date	Stack Exhaust (ppmv)
4/7/2010	2.60
5/11/2010	0.73
8/12/2010	5.42
11/4/2010	4.21
2/24/2011	4.95
Average	3.58

Notes: All concentrations are adjusted to 15% O_2.

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Table 3-10:
Summary of NOx Concentrations[1] at Inlet and Outlet of Cat Ox/SCR System

Sampling Method	Catalytic Oxidizer Inlet Concentration (ppmvd)			Catalytic Oxidizer Outlet Concentration (ppmvd)			SCR Outlet/Stack Exhaust Concentration (ppmvd)			NOx Reduction (%)
	Min.	Max.	Avg.	Min.	Max.	Avg.	Min.	Max.	Avg.	Avg.
SCAQMD Method 100.1[2]	---	---	---	---	---	---	N/A	N/A	6.6	N/A
Portable Analyzer [3]	37.9	43.5	40.9	36.4	44.0	40.1	6.9	10.2	8.4	79.5
CEMS [4]	19.3	64.7	30.7	---	---	---	0.8	15.9	7.2	77

Notes:
1) Concentrations are presented in parts per million by volume dry (ppmvd) at 15% O_2.
2) Method 100.1 measurements by SCEC were performed at the stack exhaust only.
3) NOx concentrations by portable analyzer are measured routinely starting on April 7, 2010, after initial mapping of the SCR system.
4) NOx and CO CEMS data is based on an average of the 15-minute average NOx and CO concentrations for each calendar day. CEMS data was not collected at the Cat Ox outlet.
5) N/A indicates not applicable.

Table 3-11:
Count of Periods and Events with NOx Concentration Above 11 ppmvd

Number of 15-minute periods when NOx stack exhaust concentration exceeded 11 ppmvd		Total High NOx Outlet Events[4]	% of Total Operating Time[5]
Operational Issues and System Adjustments[1,2]	703	7	3.3
Engine start-up (30 minutes)[3]	56	29	0.3
Total Non-Valid	**759**	**36**	**3.6**
Increase in NG Fuel Composition	43	17	0.2
High Load (>100%)	63	22	0.3
Other	75	22	0.4
Total Valid	**181**	**61**	**0.9**
Total	**940**	**97**	**4.5**

Notes: 1) Operational issues occurred 7/1/10-7/4/10, 12/29/10-1/4/11, 3/14/11, 3/17/11, and 3/22/11.
2) NOx at the stack exhaust exceeded 11 due to system adjustments to the urea injection system.
3) The first 30 minutes after start-up of the engine are exempt from amended Rule 1110.2. Data was excluded where NOx at the stack exhaust exceeded 11 ppmvd during engine start-up.
4) An "event" is defined as one or more consecutive 15-minute periods or periods in close succession where the NOx outlet concentration exceeded 11 ppmvd.
5) The total engine operating time is 21,285 15-minute periods (approximately 5,321 hours).

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Table 3-12:
Summary of All vs. Validated NOx Inlet and Outlet Concentrations

Parameter	NOx Engine Exhaust (ppmvd)	All NOx Stack Exhaust (ppmvd)	Validated NOx Stack Exhaust (ppmvd)
Average	30.68	7.53	7.16
Minimum	10.72	0.80	0.80
Maximum	64.70	45.23	15.88
Number NOx Stack Exhaust Periods > 11 ppmvd	N/A	940	181
Percentage of 15-minute periods > 11 ppmvd	N/A	4.4%	0.9%

Notes: 1) Concentrations are presented in parts per million by volume dry (ppmvd) at 15% O_2.
2) NOx CEMS data is based on the 15-minute average NOx concentrations from June 8, 2010 through March 31, 2011.
3)   N/A indicates not applicable

Table 3-13:
Ammonia Concentration Sampling Event Summary

Date	Engine Load (%)	Free NH_3 Field Measurement[1] (ppmv)	Total NH_3 Calculated Value[2] (ppmv)	Free NH_3 SCAQMD Method 207.1 (ppmv)
4/7/2010 & 4/8/2010	65	<MDL	1.66	0.12
	90			0.18
	105			0.43
4/21/2010	110	<MDL	0.09	N/A
4/29/2010	90	<MDL	0.00	N/A
5/6/2010	94	<MDL	2.18	N/A
5/19/2010	100	<MDL	2.54	N/A
6/29/2010	100	<MDL	0.97	N/A
7/28/2010	100	<MDL	0.63	N/A
8/12/2010	95	<MDL	2.50	N/A
11/4/2010	100	<MDL	4.95	N/A
1/12/2011	100	<MDL	0.32	N/A
2/24/2011	100	<MDL	0.09	N/A
5/10/2011	70	<MDL	1.12	0.37
	90		1.60	0.31
	110		3.12	0.38

Notes: 1) Free ammonia field measurements are taken using MDL to 2.5-3 ppm range and 2 to 30 ppm range Draeger® tubes.
2) Total ammonia was determined based on the theoretical calculation which uses NOx inlet and NOx outlet of the catalytic oxidizer/ SCR system and the urea injection rate. The calculated value reported is based on the 15-minute block averages from the CEMS for the time period when the exhaust gas sample was taken for the field measurement. No correction factor was applied.
3) <MDL: below Method Detection Limit.
4) N/A indicates not applicable. No data was taken using Method 207.1 during these field measurement events.

Table 3-14:
Catalytic Oxidizer /SCR System Performance Proposal

Urea usage estimate (32.5% urea solution) @ 80% NOx reduction	1.1 gallons/hour
Estimated pressure drop across catalytic oxidizer using a 4040 arrangement with one layer of standard depth (~ 3.5") catalyst elements @ 200 CPSI = A	0.7 in. wc.
Estimated pressure drop across SCR converter using a 4040 arrangement with two layers of standard depth (~ 3.5") catalyst elements @ 200 CPSI = B	1.4 in. wc.
Estimated pressure drop across 12 foot long mixing duct with one static mixer installed = C	1.9 in. wc.
Total system pressure loss estimate (includes loss through oxidation converter, SCR converter, expansion joint, and mixing duct) using 4040 oxidation catalyst and two layers of 4040 SCR catalyst (A + B + C)	4.0 in. wc.
Estimated pressure drop across one additional layer (~ 3.5") of either catalytic oxidizer or SCR elements that are 200 CPSI	0.7 in. wc.
Additional system pressure drop loss estimate if an additional layer (~ 3.5") of 100 CPSI catalyst in the 4040 housing is employed	0.4 in. wc.
Additional system pressure drop loss estimate if an additional layer (~ 2") of 200 CPSI catalyst in the 4040 housing is employed	0.3 in. wc.

Notes: Estimates provided by Johnson Matthey in their system proposal, dated May 8, 2009.

Table 3-15:
Catalytic Oxidizer /SCR System Performance Data

	Unit	Average Value
Urea Injection Rate	gallon per hour	0.62
Catalytic Oxidizer Inlet Temperature	°F	781
Catalytic Oxidizer Outlet Temperature	°F	779
Catalytic Oxidizer Differential Pressure	in. wc.	0.3
SCR Inlet Temperature	°F	796
SCR Outlet Temperature	°F	756
SCR Differential Pressure	in. wc.	1.0

Notes: 1)   Estimates are provided by the data logger located inside of the urea injection cabinet for the period of April 1, 2010 through November 4, 2010 and January 1, 2011 through February 24, 2011.

2)   The data have been validated to remove periods where the engine was offline, as indicated when urea injection is offline, temperatures in the catalysts cool and NOx inlet value drop.

Figure 3-1: Catalytic Oxidizer Inlet and Outlet CO Concentration
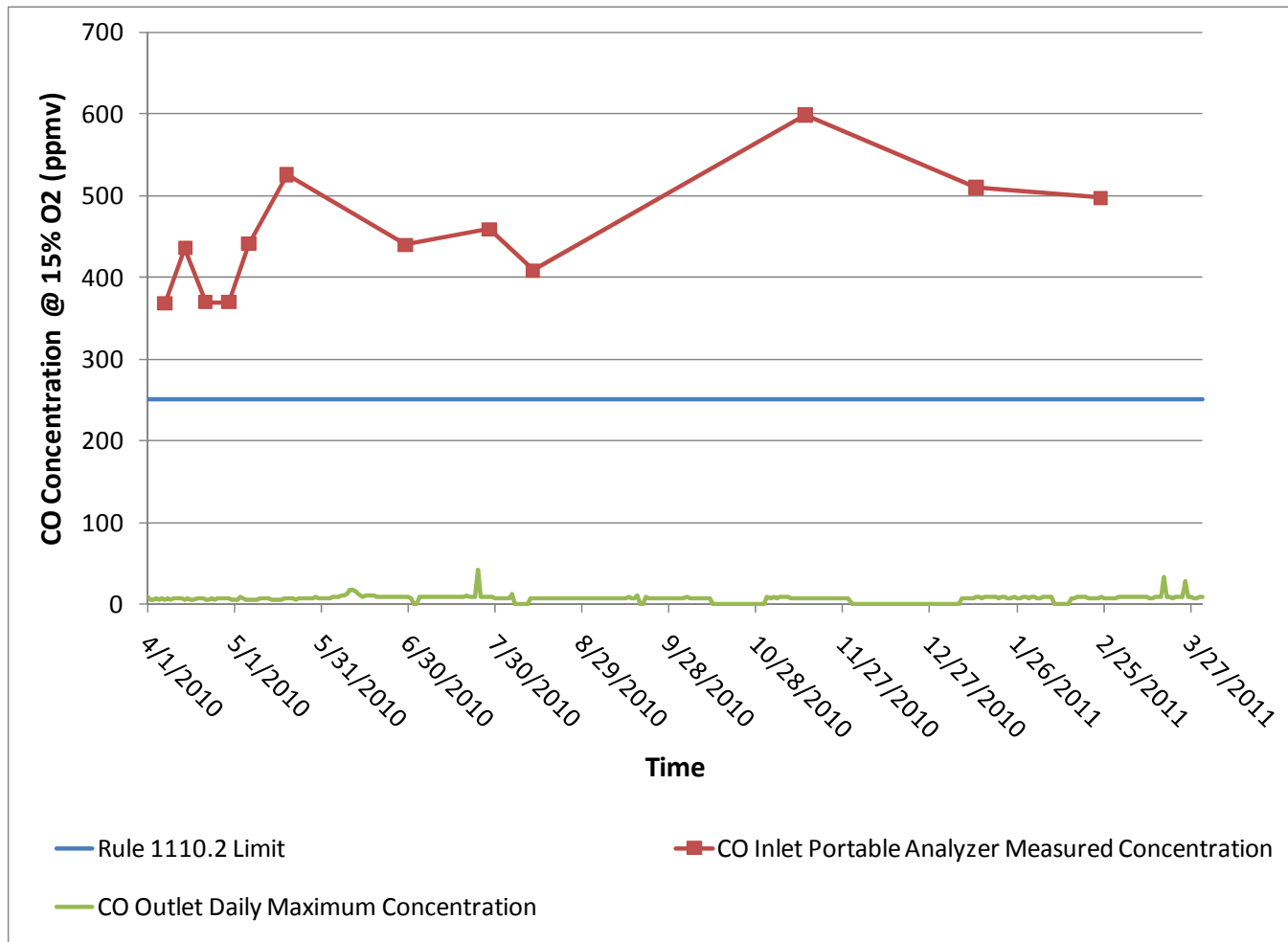
Notes: 1) The first 30 minutes after start-up of the engine are exempt from amended Rule 1110.2. Data was excluded where NOx at the stack exhaust exceeded 11 ppmvd during engine start-up.
2) CEMS values shown are maximum values for each calendar day and may not all occur at the same time as the portable analyzer measurement.
3) Spikes where inlet and outlet NOx concentrations drop to 0 ppmv occur when the engine is offline.

Figure 3-2: Selective Catalytic Reduction Inlet and Outlet NOx Concentration
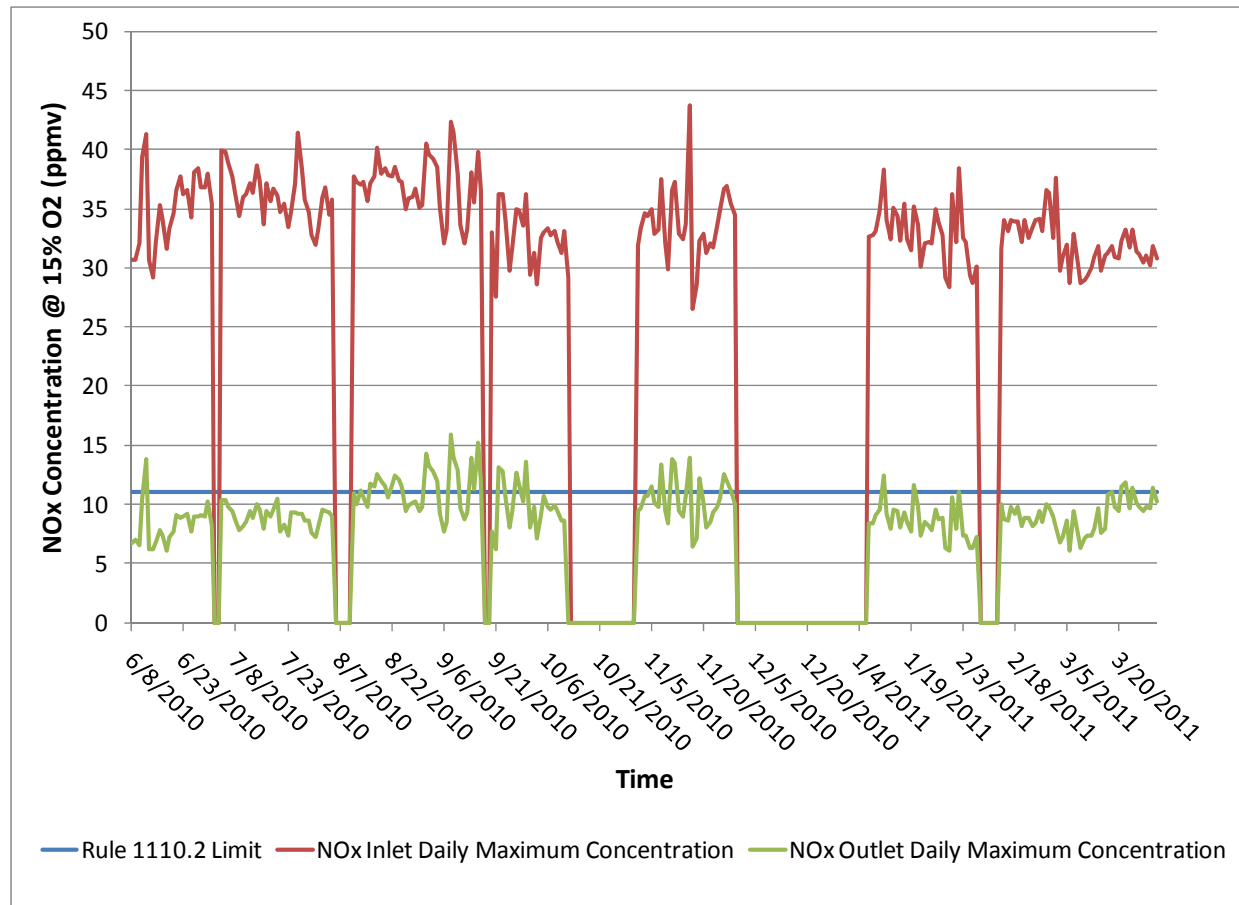
Notes:
1) The first 30 minutes after start-up of the engine are exempt from amended Rule 1110.2. Data was excluded where NOx at the stack exhaust exceeded 11 ppmvd during engine start-up.
2) Data was excluded where NOx at the stack exhaust exceeded 11 due to system adjustments to the urea injection system.
3) Data was excluded where operational issues occurred from 7/1/10-7/4/10, 12/29/10-1/4/11, 3/14/11, 3/17/11, and 3/22/11.
4) Values shown are maximum values for each calendar day and may not all occur at the same time within the day.
5) Spikes where inlet and outlet NOx concentrations drop to 0 ppmv occur when the engine is offline.

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Figure 3-3: Selective Catalytic Reduction Estimated Total Ammonia Concentration
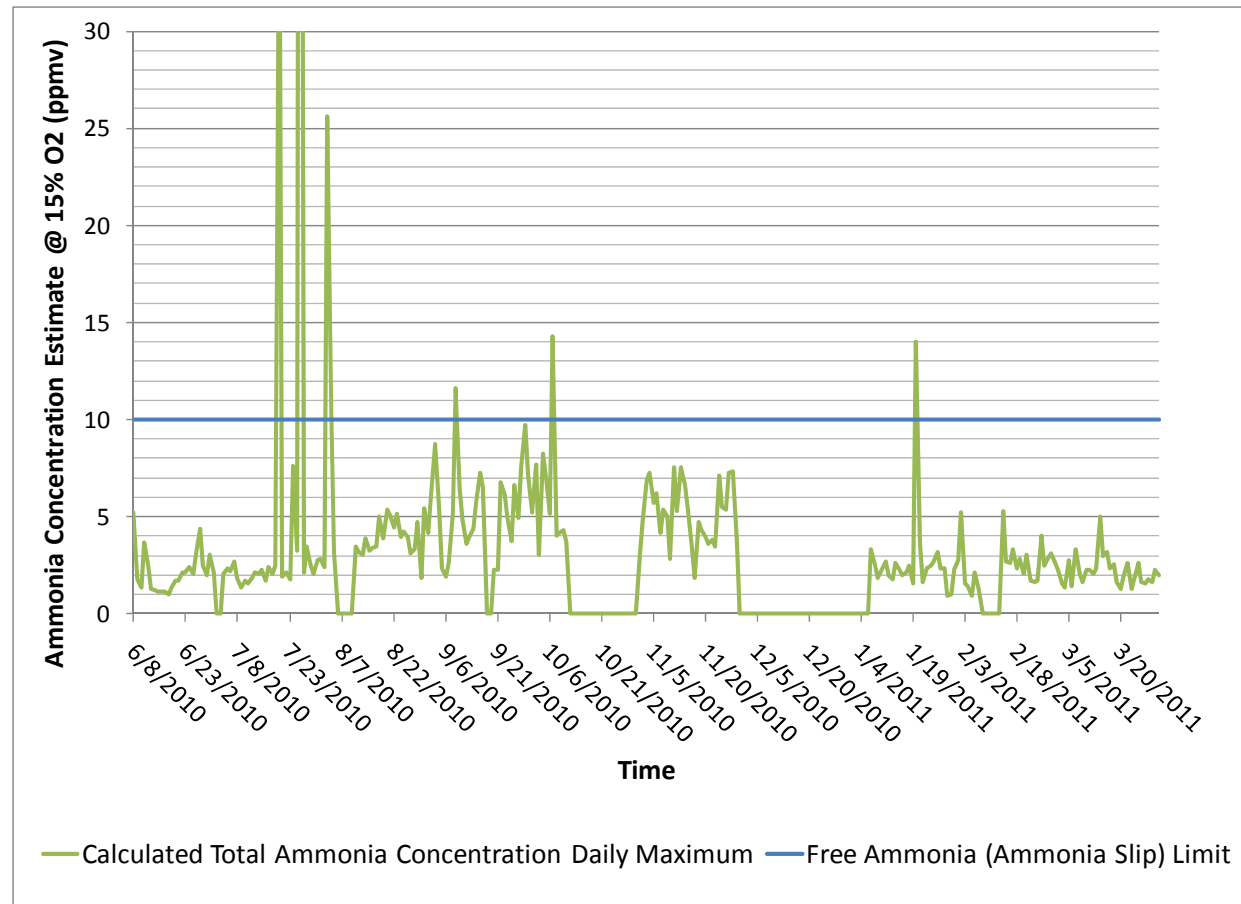
Notes:
1) The first 30 minutes after start-up of the engine are exempt from amended Rule 1110.2. Data were excluded where NOx at the stack exhaust exceeded 11 ppmvd during engine start-up.
2) Data were excluded where the SCR system was offline due to system adjustments to the urea injection system.
3) Data were excluded where operational issues occurred from 7/1/10-7/4/10, 12/29/10-1/4/11, 3/14/11, 3/17/11, and 3/22/11.
4) Values shown are maximum 15-minute values for each calendar day.
5) Spikes where inlet and outlet ammonia concentrations drop to 0 ppmv occur when the engine is offline.
6) Ammonia concentration values reported on July 20, 2010 and July 26, 2010 occurred within one hour of an engine shutdown or startup and were not part of the 30-minute exemption from amended Rule 1110.2.

4. Cost Effectiveness Analysis

A cost analysis for the implementation of the DGCS and Cat Ox/SCR systems at Plant 1 Engine 1 was performed. The cost analysis was developed for one digester gas cleaning vessel, with an approximate capacity of 9,900 lbs of carbon media and associated piping, and one Cat Ox/SCR system with platform installation.

4.1. Capital and Operation & Maintenance Costs

The capital project budget includes the following construction costs: equipment; installation; mechanical; structural; electrical; site/architectural; instrumentation; and material sales tax; as well as the construction contractor's expenses, such as contractor overhead, profit, mobilization, bonding, and insurance. For capital cost the following assumptions apply:

- The construction cost subtotal is time dated for June 2009 and based on the pilot test construction contract price, including change orders.

- The equipment cost is time dated for June 2009 and based on the pilot test costs of the following equipment: one Cat Ox/SCR system with urea injection control cabinet for Plant 1 Engine 1; one digester gas cleaning vessel with inlet, outlet, and bypass piping sized to treat 100 percent of the digester gas for the Plant 1 cogeneration facility; one NOx probe and umbilical sample line from the Engine 1 exhaust to the CEMS panel in the control room; and seven expansion joints for the engine exhaust ductwork.

- Project design and engineering is assumed to be 15% of the total construction and equipment cost.

- The annualized total capital project budget is based on a 20-year evaluation period and 4.0 percent annualized rate, as set forth in the SCAQMD July 9, 2010 Board Meeting Minutes, Attachment B: Assessment of Available Technology for Control of NOx, CO and VOC Emissions from Biogas-Fueled Engines – Interim Report.

Annual O&M costs associated with operating the digester gas cleaning system and Cat Ox/SCR system includes the following components:

- Annual additional electrical cost;

- Annual carbon media replacement costs;

- Oxidation and SCR catalyst replacement costs;

- Annual urea usage costs;

- Annual equipment maintenance costs;

- Periodic siloxane, VOC, and H_2S testing;

- The reduction in O&M costs due to the use of clean digester gas was considered. Such reduction in O&M costs includes a reduction in frequency of major maintenance interval service and maintenance shutdowns related to siloxane compounds present in the digester gas.

- The reduction in annual emissions fees for NOx, VOC, CO, and formaldehyde based on the estimated emissions reductions realized from the engine exhaust control system was considered.

The assumptions related to the O&M costs are the following:

- Annual operating hours of a single engine at Plant 1 is estimated to be 6,000 hours.

- The change-out of the carbon media for the digester gas cleaning system is estimated to be approximately $40,000 per change-out. The change-out frequency with three engines operating at Plant 1 at 6,000 annual operating hours is approximately three (3) times per year. The total annual cost of carbon media for three engines at 6,000 annual operating hours is $120,000 per year. Therefore, the cost for carbon media for a single engine is approximately $40,000 per year.

- The replacement of the sixteen catalytic oxidizer media blocks and thirty-two SCR catalyst media blocks is estimated to take place once every three years for each engine. Although the Cat Ox/SCR system demonstrated performance for one year during the pilot testing period, it is assumed that the media will perform for three years based on the vendor warranty of 16,000 operating hours. Assuming that each engine operates for 6,000 hour per year, the engine should reach 16,000 operating hours in 2 years and 8 months. The costs of each catalytic oxidizer media block and SCR catalyst media block are $3,450 and $1,850, respectively.

- Urea cost is assumed to equal $4.50 per gallon, including tax, at an average rate of 0.7 gallons per hour for 6,000 annual operating hours.

- Equipment maintenance and testing is assumed to equal $5,000 per year for annual maintenance of the SCR urea injection system, $5,400 per year for siloxane testing ($600 per sample, 3 samples per change out, and 3 change outs per year), and $3,000 per year for VOC and H_2S sampling.

- Annual reduced engine maintenance cost using cleaned digester gas, assumed to equal $130,641 for three engines operating at 6,000 hours annually. Therefore, the approximate savings per engine is approximately $43,547 per year as estimated by OCSD. Currently, the three engines at Plant 1 are consuming all of the digester gas produced by the facility. Therefore, although the annual cost of maintenance is decreased, the total operating time of each engine will remain the same.

- Calculation of emissions reductions for NOx, VOC, and CO is provided in Scenario 2 in Section 4.2 below. Scenario 2 assumed that the uncontrolled NOx, VOC, and CO emissions were based on the results from the 2011 Annual Compliance Test for Engines 2 and 3. The controlled emissions were based on the Rule 1110.2 limits of 11 ppmv for NOx and 30 ppmv for VOCs, and the pilot testing results of 15 ppmv for CO. Fees per ton of NOx, VOC, and CO are assumed to be $270.26, $576.75, and

$3.57, respectively, based on the Annual Emission Report provided by the OCSD dated February 23, 2011.

- The uncontrolled emissions of formaldehyde were based on the results of the 2009 Annual Compliance Test for Engine 3 of 1.4 lb/hr. The controlled emissions of formaldehyde were based on the results of the 2011 Annual Compliance Test for Engine 1 of 0.069 lb/hr. It is assumed that the annual operating hours of a single engine at Plant 1 is 6,000 hours. Therefore, formaldehyde emissions reduction is 4.13 tons per year. The fee per ton of formaldehyde is assumed to be $800.00 based on the Annual Emission Report provided by the OCSD dated February 23, 2011.

- Annual O&M costs do not include the cost of ammonia sampling because it is assumed that ammonia sampling is part of the annual compliance test. The estimated ammonia sampling cost is $2,500 for one sampling event per year using SCAQMD Method 207.1. The annual cost of weekly ammonia testing using Draeger® tubes or similar colorimetric tubes is assumed to equal $300.

The capital cost and annual O&M costs for a single engine is presented in Table 4-1.

4.2. Unitized Cost of Carbon Media and Emissions Reduction

The cost of implementation of the DGCS and Cat Ox/SCR systems can be unitized as a cost per cubic foot of digester gas treated or as a cost per ton of NOx and VOC reduced in the emissions. The following summarizes these metrics for evaluating costs.

4.2.1. Cost for Volume of Digester Gas Treated

A metric for evaluating the cost of the DGCS is the cost per cubic foot of digester gas treated. This metric is based on the frequency of the carbon media change-out as well as the cost per change-out. The digester gas volume that passed through the catalyst during the pilot test ranged from 146 MMcf to 169 MMcf. The cost of each carbon media change-out is assumed to be approximately $40,000. Therefore, the cost per treated digester gas ranges between $237/MMcf and $274/MMcf. The capacity of the digester gas cleaning vessel is 9,900 pounds of carbon media. Therefore the media per volume of treated digester gas ranges between 59 lbs/MMcf and 68 lbs/MMcf. Note that these are conservative estimates. The pilot test only utilized a single digester gas cleaning vessel as opposed to a lead/lag configuration in which two vessels, a lead vessel followed by a second lag vessel, are used. Therefore, the carbon media was replaced more frequently than necessary to prevent potential breakthrough of siloxane compounds that may foul the catalyst. In a lead/lag configuration, the volume of gas treated between change-outs can be extended since breakthrough can be allowed to occur in the lead vessel because any siloxane compounds would be removed in the lag vessel.

4.2.2. Cost for Reductions in NOx and VOCs, and CO Emissions

A metric for evaluating the cost effectiveness of the Cat Ox/SCR system is cost per ton of NOx, VOC, and CO removed by the system. Based on the total annualized cost per

engine, two scenarios for estimating NOx, VOC, and CO emissions reduced were developed. The following are the assumed uncontrolled and controlled concentrations for the two scenarios:

Scenario 1

- Uncontrolled concentrations are based on the current permit limits of 45 ppmv of NOx, 209 ppmv of VOCs, and 2,000 ppmv of CO, each at 15% O_2.

- Controlled emissions are based on the future Rule 1110.2 limits of 11 ppmv of NOx and 30 ppmv of VOCs, each at 15% O_2. Controlled emissions for CO are based on 15 ppmv because the Cat Ox/SCR system consistently reduced CO emissions well below the Rule 1110.2 limit of 250 ppmv. The concentration of 15 ppmv provides a factor of safety of 2 over the average CO concentration of 7.5 ppmv. The factor of safety gives credit for projected emissions reduction, but allows for reduced efficiency as the catalyst approaches the end of its lifecycle, prior to replacement.

Scenario 2

- Uncontrolled concentrations from the 2011 Annual Source Test Report are 31 ppmv of NOx, 97 ppmv of VOCs, and 371 ppmv of CO at 15% O_2 for Plant 1 (Engines 2 and 3).

- Controlled emissions are based on the future Rule 1110.2 limits of 11 ppmv of NOx and 30 ppmv of VOCs, each at 15% O_2. Controlled emissions for CO are based on 15 ppmv because the Cat Ox/SCR system consistently reduced CO emissions well below the Rule 1110.2 limit of 250 ppmv. The concentration of 15 ppmv provides a factor of safety of 2 over the average CO concentration of 7.5 ppmv. The factor of safety gives credit for projected emissions reduction, but allows for reduced efficiency as the catalyst approaches the end of its lifecycle, prior to replacement.

The assumptions used for each scenario were:

- Annual operating hours of a single engine at Plant 1 is estimated to be 6,000 hours;

- Exhaust flowrates are based on high load; and

- VOCs emissions are calculated as methane.

Table 4-2 provides a summary of the cost effectiveness for the two scenarios for one engine at Plant 1. The cost effectiveness in terms of dollars per ton of NOx and VOCs reduced for Scenarios 1 and 2 was $7,987 and $17,585, respectively. The cost effectiveness in terms of dollars per ton of CO reduced for Scenarios 1 and 2 was $363 and $3,546, respectively. Note that the cost effectiveness for CO is conservative since the annualized cost is based on the entire system including the SCR and urea injection system.

Table 4-1:
Estimated Capital and O&M Costs for Plant 1 Engine 1

Capital Cost	Plant 1 Engine 1[1]
Equipment (Cat Ox/SCR, DGCV, CEMS, Expansion Joints)	$708,000
Labor and Contractor Cost[2]	
Bonding/Insurance	$21,272
Mobilization	$56,748
Prime Contractor Labor and Construction (i.e. concrete & rebar, piping, fittings, valves, installation & start-up, management, etc.)	$765,723
Steel Subcontractor (i.e. structural steel, miscellaneous metal, handrail, grating)	$249,941
Insulation Subcontractor	$82,879
Electrical Subcontractor (i.e. wiring, conduit, grounding, etc.)	$76,311
Painting Subcontractor	$28,655
Labor and Contractor Cost Subtotal (including contractor markups for overhead, profit, mobilization, bonding, insurance)	$1,281,529
Construction Subtotal (June 2009 dollars)	$1,989,529
Project Design and Engineering (15% of construction subtotal)	$298,429
Total Capital Cost	$2,287,958
Annualized Capital Cost (4 % annual rate, 20 years)	$168,352
Annual O&M Cost for 1 Engine (operating 6,000 hrs/yr)[3]	**Plant 1 Engine 1**
Carbon Media Replacement	$40,000
Catalyst Replacement	$38,133
Urea Cost	$18,900
Electrical Cost	$1,200
Equipment Maintenance and Testing	$13,400
Reduced Engine Maintenance	$(43,547)
Reduced Emission Fees	$(9,136)
Annual O&M Cost per Engine	$58,950
Total Annual Capital and O&M Cost for 1 Engine	**Plant 1 Engine 1**
Total Annualized Cost per Engine	**$227,302**

Notes:
1) Engine Size: 2,500 kW/3,471 bhp
2) Subcontractor costs include a 10% prime contractor markup.
3) Assumptions for the basis of O&M costs is provided in Section 4.1.

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Table 4-2:
Cost per Ton NOx and VOC Emissions Reduced at Plant 1 Engine 1

Capital Cost	Plant 1 Engine 1
Annualized Capital Cost (4 % annual rate, 20 years)	$168,352
Annual O&M Cost per Engine[1,2]	$58,950
Total Annualized Cost per Engine	**$227,302**
Scenario 1	**Plant 1 Engine 1**
Uncontrolled NOx – Current Permit Limit (ppmv)	45
Controlled NOx – Future Rule 1110.2 Limit (ppmv)	11
Uncontrolled VOC – Current Permit Limit (ppmv)	209
Controlled VOC – Future Rule 1110.2 Limit (ppmv)	30
Uncontrolled CO – Current Permit Limit (ppmv)	2,000
Controlled CO (ppmv)[3]	15
NOx Reduction (ton/yr)	10.05
VOC Reduction (ton/yr)	18.41
CO Reduction (ton/yr)	357.21
Cost Effectiveness ($/ton of NOx and VOC reduced)	**$7,987**
Cost Effectiveness ($/ton of CO reduced)	**$636**
Scenario 2	**Plant 1 Engine 1**
Uncontrolled NOx – 2011 Source Testing Data (ppmv)	31
Controlled NOx – Future Rule 1110.2 Limit (ppmv)	11
Uncontrolled VOC (ppmv)	97
Controlled VOC – Future Rule 1110.2 Limit (ppmv)	30
Uncontrolled CO – 2011 Source Testing Data (ppmv)	371
Controlled CO (ppmv)[3]	15
NOx Reduction (ton/yr)	6.03
VOC Reduction (ton/yr)	6.89
CO Reduction (ton/yr)	64.10
Cost Effectiveness ($/ton of NOx and VOC reduced)[4]	**$17,585**
Cost Effectiveness ($/ton of CO reduced)[4]	**$3,546**

Notes:
1) Engine Size: 2,500 kW/3,471 bhp
2) Annual Operating Hours: 6,000 hours/year
3) Controlled emissions for CO are based on 15 ppmv because the Cat Ox/SCR system consistently reduced CO emissions well below the Rule 1110.2 limit of 250 ppmv. The concentration of 15 ppmv provides a factor of safety of 2 over the average CO concentration of 7.5 ppmv.
4) Cost effectiveness of NOx and VOC reduced and CO reduced are calculated separately. The cost effectiveness of NOx and VOC is equal to the annualized cost per engine divided by the sum of NOx and VOC tons per year reduced. The cost effectiveness of CO is equal to the annualized cost per engine divided by the CO tons per year reduced and does not take NOx or VOC reduction into consideration.

5. Conclusions and Recommendations

In order to evaluate if the amended Rule 1110.2 limits could be met for their digester gas-fired IC engines, OCSD proposed to perform a pilot study on Engine 1 at Plant 1.   In previous studies, OCSD had identified a catalytic oxidizer and SCR system along with a DGCS as the most feasible technology to lower air toxic emissions and to meet the new lower emissions limits. Because SCAQMD recognized that the emission limits in the new Rule 1110.2 were "technology-forcing," they provided a grant to OCSD to support the pilot study at Plant 1 Engine 1 as part of a Rule 1110.2 technology assessment study to determine if cost-effective and commercial technologies are available to comply with the new lower emission limits. The 12-month pilot study at Plant 1 evaluated the effectiveness of the control systems to meet Rule 1110.2 limits.

5.1. System Performance

The DGCS system, in general, removed siloxanes from the digester gas to below MDL levels and significantly reduced sulfur compounds and VOCs successfully reducing catalyst masking which should lead to extended catalyst life. Additional benefits of the contaminant removal were significant improvements in engine maintenance requirements, and lower O&M costs. The use of cleaned digester gas resulted in much less frequent maintenance requirements for the engine, including longer time intervals between spark plug changes and major maintenance events.

There were no notable back pressure effects on engine performance due to the installation of the Cat Ox/SCR system with a DGCS during the pilot test. The system design back pressure for the Cat Ox/SCR system and additional exhaust ductwork was estimated to not exceed 9 in. wc. per the engine manufacturer's recommendations. Based on the data monitored during the pilot test, the average differential pressure through the catalytic oxidizer and SCR systems are approximately 0.3 and 1.0 in. wc, respectively.

The combined Cat Ox/SCR system with digester gas cleaning evaluated in the pilot study resulted in significant reductions in CO, VOC, and NOx emissions from the digester gas fired IC engine at Plant 1 providing substantial air quality benefits from this system. In addition, NOx and CO, along with VOCs (as NMNEOCs) are considered indirect greenhouse gases, affecting tropospheric ozone and methane levels.

5.2. Comparison to Rule 1110.2 Limits and Other Criteria

- The average NOx concentration at the stack exhaust after the pilot study Cat Ox/SCR system was approximately 7 ppmv, below the 11 ppmv under amended Rule 1110.2. The lowest NOx stack exhaust concentration met consistently under all valid conditions was 16 ppmv. While there were some periods when the NOx stack exhaust

MALCOLM PIRNIE | ARCADIS
The Water Division of ARCADIS
Orange County Sanitation District
Pilot Testing of Emission Control System Plant 1 Engine 1
Final Report July 2011

5-1

concentration was above 11 ppmv; after screening these periods to eliminate unusual operational events or start-up conditions, 181 periods out of 21,285 total operating periods (approximately 5,321 hours) remained as valid periods where the NOx stack exhaust concentration was above the new Rule 1110.2 limit. These periods occurred during 61 separate events and accounted for less than 0.9% of the total measurement periods during the pilot study.

■ Free ammonia (ammonia slip), the result of excess urea injection in the SCR system, was below 0.5 ppmv using SCAQMD compliance sampling methods and below the MDL using Draeger® tubes over the course of the pilot study. The total ammonia calculation method, unlike the measurement methods for free ammonia, did predict low levels of total ammonia. It was noted that the total ammonia calculation method estimates did not include the use of a project-specific correction factor, CF, which could be used to account for secondary reactions that would consume ammonia, thus bringing the total ammonia calculation method estimates more in line with the measurements of free ammonia.

■ The maximum CO concentration at the stack exhaust (42.2 ppmv) was well below the amended Rule 1110.2 emission limit of 250 ppmv.

■ The maximum VOC concentration at the stack exhaust (4.95 ppmv) was consistently well below the 30 ppmv in amended Rule 1110.2.

Therefore, with the exception of a relatively limited number of periods when the NOx stack exhaust concentration was above the new amended Rule 1110.2 limit, the combined Cat Ox/SCR system equipped with a DGCS was able to meet the new emission limits.

5.3. Cost Effectiveness

The total capital costs to design, procure, and install a digester gas cleaning vessel to clean all the digester gas to the Plant 1 engines, and a Cat Ox/SCR system with auxiliary equipment for Engine 1 is estimated to be $2,300,000. The annual O&M cost for these systems at Plant 1 is approximately $59,000. Assuming a 20-year lifespan, the total annualized cost (capital cost plus O&M) for the DGCS and Cat Ox/SCR systems for Plant 1 Engine 1 is $227,000.

The cost effectiveness analysis (based on dollars per ton of NOx, VOC and CO emissions reduced) was developed for two scenarios: Scenario 1 assumed that the uncontrolled emissions were based on permit limits (i.e., 45 ppmv, 209 ppmv, and 2,000 ppmv, respectively), and Scenario 2 assumed that the uncontrolled emissions were based on the results from the 2011 Annual Compliance Test for Engines 2 and 3. Both scenarios assumed that the controlled emissions were based on the Rule 1110.2 limits of 11 ppmv for NOx, 30 ppmv for VOCs, and the pilot testing results of 15 ppmv for CO. Under these assumptions, the cost effectiveness estimates for Scenarios 1 and 2 are $7,987 and $17,585, respectively, per ton of NOx plus VOCs reduced. The cost effectiveness estimates for Scenarios 1 and 2 are $636 and $3,546, respectively, per ton of CO reduced.

Note that the cost effectiveness for CO is conservative since the annualized cost is based on the entire system including the SCR and urea injection system. The annualized cost and emissions reduced calculations were based on operating each engine for a maximum of 6,000 hours per year.

5.4. Recommendations

SCR systems similar to the Johnson Matthey system used in the present pilot study are commercially available and have successfully demonstrated NOx control for single fuels, such as natural gas. However, based on previous source testing data, the NOx concentration is higher for natural gas than digester gas at a given load; therefore, there is a potential for variations in NOx concentration at the inlet to the SCR system at a given load due to the varying fuel blend in biogas-fueled engines. Since the urea injection rate can only be established based on engine load and not inlet NOx concentration, it is difficult to maintain a targeted NOx limit at the stack exhaust using this type of SCR system.

NOx concentrations in the stack exhaust were above the amended Rule 1110.2 NOx limit of 11 ppmv for a small number of sampling periods during the pilot study. These periods where the NOx stack exhaust concentration was over 11 ppmv may indicate that this limit is too conservative, especially for biogas-fueled and dual-fueled engines where a steady SCR control efficiency is difficult to maintain. Recommendations regarding the new amended Rule 1110.2 NOx limit of 11 ppmv are as follows:

1. Given the variations in the engine load and urea injection rate mapping requirements for the digester gas-fired IC engine, using the 15-minute block average for compliance with the NOx emission limit may also be too restrictive, and a longer averaging time may be more appropriate for biogas-fired engines. Alternatively, allowing a limited number of excursions above the 11 ppmv for biogas-fueled engines, for example, 5% of the total annual continuous (i.e., 15-minute averaging periods) NOx data, to account for the difficulty in accurately mapping the urea injection rate to control NOx outlet concentration, may also be warranted.

2. In April 2011, after the official pilot testing period concluded, a Johnson Matthey technician adjusted the urea injection rate curve to 1) expand the curve to a maximum of 125% engine load and 2) to increase the urea injection rate at high engine loads. The increase in urea injection rate should accommodate for the increased NOx production when the engine combusts a fuel blend with a higher percentage of natural gas. Further observation will be required to confirm if these adjustments will lead to a reduction in the number of periods where stack exhaust NOx outlet concentration is above 11 ppmv.

Further sampling of the exhaust emissions can be performed to establish a correction factor for the estimated total ammonia calculation method and to confirm that the SCR system does not produce measureable free ammonia. Recommendations regarding the estimated total ammonia calculation method are as follows:

3. The presence of sulfur dioxide and sulfur trioxide in the exhaust gas before the SCR, and ammonium sulfate and ammonia bisulfate in the exhaust gas after the SCR, can indicate secondary reactions between the ammonia and sulfur compounds in the exhaust gases taking place due to the injection of urea. The correction factor, CF, can be used in the estimated total ammonia calculation method to account for these reactions, thus improving this calculation for estimating free ammonia.

4. Although the pilot study data indicates that there is minimal, if any, free ammonia due to the SCR system, it is recommended that the OCSD perform additional and routine testing for free ammonia during varying loads and fuel blends over a period of time to accumulate data corroborating that the SCR system does not produce measurable free ammonia under all operating conditions for a given mapped urea injection versus engine load set point.

ATTACHMENT C

APPENDIX A, B, AND C OF ORANGE COUNTY SANITATION DISTRICT FINAL REPORT

APPENDIX A-1:

**SCAQMD Permit to Construct/Operate
for an Experimental Research Project**

October 15, 2009
A/N 497717

ORANGE COUNTY SANITATION DISTRICT
10844 Ellis Avenue
Fountain Valley, CA 92708

Attention: Mike D. Moore
Manager - Environmental Compliance & Regulatory Affairs

Gentlemen:

PERMIT TO CONSTRUCT / OPERATE
FOR AN EXPERIMENTAL RESEARCH PROJECT

The system described below is granted a Permit to Construct and Operate (Application Number 497717) as allowed by and under the conditions set forth by Rule 441 of the Rules and Regulations of the South Coast Air Quality Management District and is subject to the special conditions listed.

EQUIPMENT DESCRIPTION:

DIGESTER GAS FUEL PRETREATMENT, POST-COMBUSTION CATALYTIC OXIDATION AND SELECTIVE CATALYTIC REDUCTION SYSTEMS FOR ENGINE NO. 1 (PO G2957), CONSISTING OF;

1. DIGESTER GAS (DG) CLEANING VESSEL, 7.5' DIA. X 8' H., CONTAINING MINIMUM OF 9,500 LBS OF GRANULAR ACTIVATED CARBON MEDIA, WITH ASSOCIATED DIGESTER GAS SUPPLY AND RETURN LINES, VALVES, TEMPERATURE, DIFFERENTIAL PRESSURE DROP GAUGES, AND CONDENSATE DRIP TRAP.

2. CATALYTIC OXIDIZER (CATOX), JOHNSON MATTHEY INC., HOUSING MODEL NO. 4040-30-36-4, 200 CPSI OXIDATION CATALYST, ALUMINUM SUBSTRATE WITH OTHER METALS, 8' L. X 0' – 4" W. X 8' H., WITH ONE LAYER OF MODULE, 18.67 CUBIC FOOT TOTAL VOLUME, AND WITH ASSOCIATED AUTOMATIC TEMPERATURE AND PRESSURE MONITORING DEVICES AND CONTROLS.

3. SELECTIVE CATALYTIC REDUCTION (SCR) CATALYST, JOHNSON MATTHEY INC., HOUSING MODEL NO. 4040-36-4, ALUMINUM SUBSTRATE WITH OTHER METALS,, 8' L. X 0' – 4" W. X 8' H., WITH TWO LAYERS OF MODULE, 37.33 CUBIC FOOT TOTAL VOLUME, AND WITH ASSOCIATED AUTOMATIC TEMPERATURE AND PRESSURE MONITORING DEVICES, AND CONTROL SYSTEMS WITH EXISTING CONTINUOUS EMISSIONS MONITORING SYSTEM (CEMS).

4. STORAGE TANK, AQUEOUS UREA SOLUTION (32.5%), 1000 GALLON CAPACITY, WITH ASSOCIATED PIPING, PUMP, FLOW CONTROL VALVES, UREA INJECTION LANCE, COMPRESSED AIR SUPPLY, AND WITH ASSOCIATED AUTOMATIC CONTROLS.

TO BE LOCATED AT: ORANGE COUNTY SANITATION DISTRICT (OCSD)
WASTEWATER TREATMENT PLANT NO. 1
10844 ELLIS AVENUE
FOUNTAIN VALLEY, CA 92708

Conditions:

1.   OPERATION OF THIS EQUIPMENT SHALL BE CONDUCTED IN COMPLIANCE WITH ALL DATA AND SPECIFICATIONS SUBMITTED WITH THE APPLICATION UNDER WHICH THIS PERMIT IS ISSUED, UNLESS OTHERWISE NOTED BELOW.

2.   THIS EQUIPMENT SHALL BE PROPERLY MAINTAINED AND KEPT IN GOOD OPERATING CONDITION AT ALL TIMES.

3.   THIS EQUIPMENT SHALL BE OPERATED BY PERSONNEL PROPERLY TRAINED IN ITS OPERATION.

4.   THIS EXPERIMENTAL RESEARCH PERMIT SHALL EXPIRE ON OCTOBER 31, 2010.

5.   SAMPLES SHALL BE COLLECTED FROM THE INLET AND THE OUTLET OF THE DIGESTER FUEL GAS CLEANING (DFGC) SYSTEM AND ANALYZED FOR TOTAL SILICON, SILOXANE AND SILOXANE COMPOUNDS, AND TOTAL SULFUR COMPOUNDS AS H2S, USING DISTRICT OR OTHER APPROVED METHODS. RESULTS SHALL BE RECORDED.

6.   WHENEVER THE DFGC SYSTEM IS IN OPERATION, THE FUEL GAS FLOW RATE (SCFM) AND TOTAL VOLUME (CUBIC FEET) PROCESSED EACH DAY SHALL BE RECORDED.

7.   WHEN CATALYTIC OXIDIZER IS IN OPERATION, THE OXIDIZER'S INLET AND OUTLET TEMPERATURE AND PRESSURE DROP READINGS SHALL BE RECORDED ONCE A SHIFT.

8.   WHEN CATALYTIC OXIDIZER IS IN OPERATION, THE CATALYTIC OXIDIZER'S INLET AND OUTLET CO AND VOC CONCENTRATIONS (PPMV) SHALL BE MONITORED, USING A PORTABLE ANALYZER AND AQMD APPROVED TEST METHODS. READINGS SHALL BE RECORDED AT START-UP AND AT LEAST ON A WEEKLY BASIS.

9.   WHEN CATALYTIC OXIDIZER IS IN OPERATION, INLET AND OUTLET SAMPLES SHALL BE COLLECTED AND SPECIATED ANALYSIS SHALL BE CONDUCTED FOR TOTAL VOCs (PPMV), INCLUDING BUT NOT LIMITED TO, FOR FORMALDEHYDE AND OTHER TOXIC COMPOUNDS PRESENT (PPMV) USING DISTRICT OR OTHER APPROVED METHODS.

10.   WHEN SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM IS IN OPERATION, THE INLET AND OUTLET TEMPERATURE AND PRESSURE DROP READINGS SHALL BE RECORDED ONCE A SHIFT.

11.   EXCEPT DURING STARTUP, THE OPERATOR SHALL MAINTAIN THE TEMPERATURE AT THE INLET TO THE CATALYST BEDS BETWEEN 600 AND 850 DEG. F.

12.   THE OPERATOR SHALL INSTALL AND MAINTAIN A UREA FLOW RATE MEASURING SYSTEM TO ACCURATELY INDICATE THE UREA INJECTION RATE TO THE SELECTIVE CATALYTIC REDUCTION SYSTEM.

13.   THE OPERATOR SHALL CONTINUOUSLY ANALYZE THE UREA INJECTION RATE, AND THE SCR
        INLET AND OUTLET NOX EMISSION RATE TO ESTIMATE THE AMMONIA CONCENTRATION IN THE
        SCR OUTLET, BASED ON ONE HOUR AVERAGE.

14.   WITHIN 90 DAYS OF COMPLETION OF THE RESEARCH EXPERIMENTS, THE ORANGE COUNTY
        SANITATION DISTRICT SHALL SUBMIT TO AQMD A COMPLETE REPORT WITH EQUIPMENT
        OPERATING PARAMETERS AND EMISSIONS RESULTS TO;
        ATTENTION: GAURANG RAWAL, REFINERY AND WASTE MANAGEMENT PERMITTING,
        21865 COPLEY DRIVE, DIAMOND BAR, CA 91765. THE SUBMITTAL SHALL INCLUDE A COPY OF
        THIS PERMIT.

15.   EMISSIONS FROM THIS EQUIPMENT, AVERAGED OVER 15 MINUTES, CORRECTED TO 15% O2 ON
        A DRY BASIS, SHALL NOT EXCEED THE FOLLOWING;

        POLLUTANT   PPMVD

        CO   590
        NO_x 45
        VOC   209
        NH_3 <10
        PM10   0.0087 GRAINS/DSCF

16.   ALL RECORDS SHALL BE KEPT AND MAINTAINED FOR A PERIOD OF AT LEAST TWO YEARS AND
        SHALL BE MADE AVAILABLE TO AQMD PERSONNEL UPON REQUEST.

It is your responsibility to comply with all laws, ordinances and regulations of other government agencies, which are
applicable to this equipment.

If you have any questions, please call Mr. Gaurang Rawal at (909) 396-2543.

                                                    Yours truly,

                                                    Charles Tupac, P.E.
                                                    A.Q.A.C. Supervisor
                                                    Refinery and Waste Management Permitting

CDT: GCR
cc: Mohan Nagavedu, AQMD
        A/N 497717 folder

APPENDIX A-2:

Schematic of Project Set-up and Process and Instrumentation Diagrams

AIR FROM
ATMOSPHERE
INTO ENGINE

NATURAL GAS
INTO ENGINE

DIGESTER GAS
INTO ENGINE

CGS ENGINE
NO 1

ENGINE
EXHAUST

CATALYTIC OXIDIZER
(CATOX)

UREA
INJECTION

SELECTIVE CATALYTIC
REDUCTION (SCR)

HEAT
RECOVERY
UNIT

STACK
EXHAUST

STACK EXHAUST
SAMPLE PORTS

CEMS
NOX, CO, O2
OUTLET PROBE

CEMS
NOX INLET
PROBE

CATOX
INLET
(ENGINE
EXHAUST)
SAMPLE
LOCATION

SCR
OUTLET
SAMPLE
LOCATION

TO ENGINE 1

TO ENGINES
2 AND 3

DGCS
OUTLET
SAMPLE
LOCATION

DGCS
INLET
SAMPLE
LOCATION

DIGESTER GAS
CLEANING
SYSTEM
(DGCS)

DIGESTER GAS FROM GAS COMPRESSORS
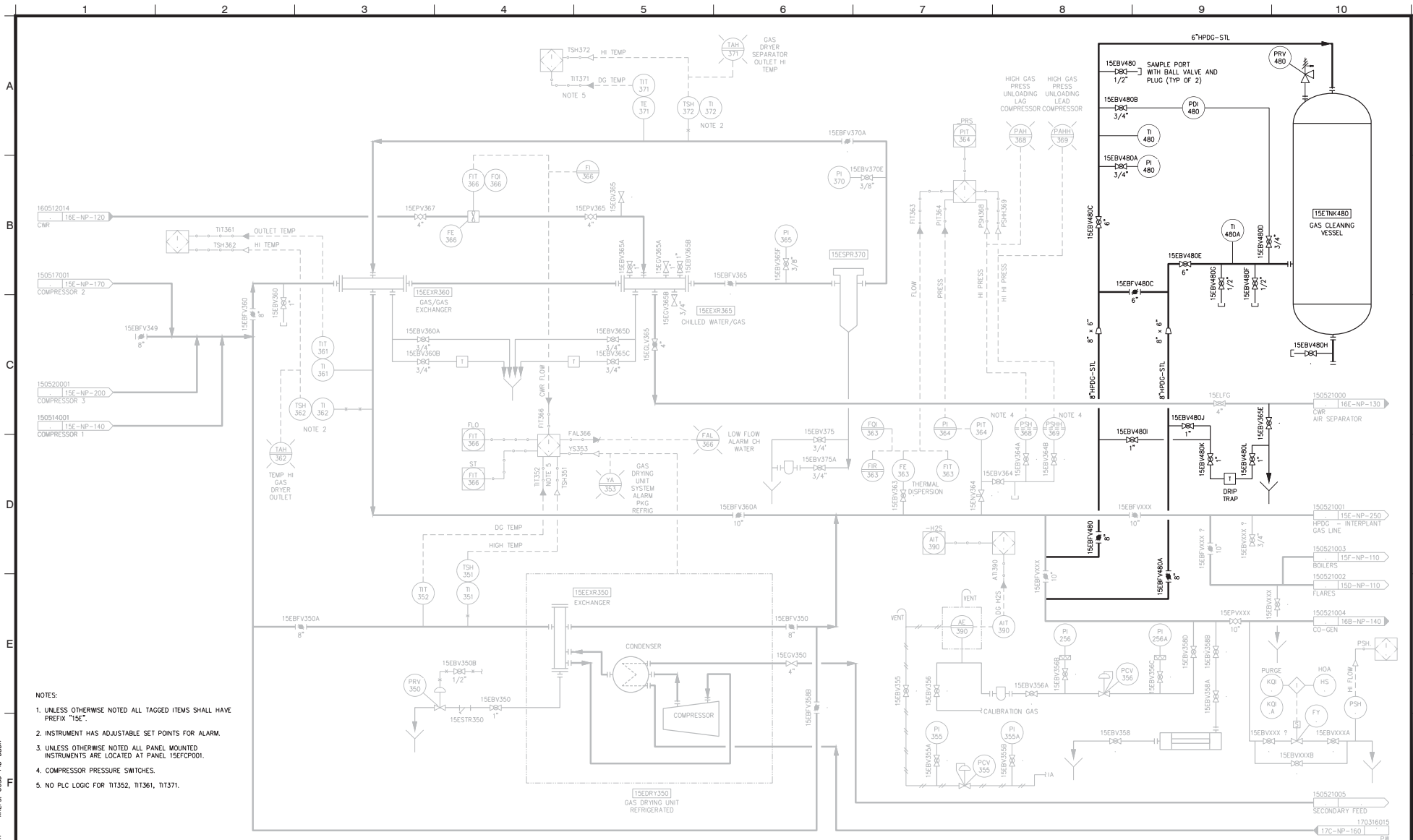
DESIGNED BY:	ZOMORODI, S. – 1/11
DRAWN BY:	RIVAS, A – 1/11
CHECKED BY:	NIU, E – 1/11

LINE IS 2 INCHES
AT FULL SIZE
(IF NOT 2"–SCALE ACCORDINGLY)

MALCOLM PIRNIE

ORANGE COUNTY
SANITATION DISTRICT

PLANT NO.1-PILOT TEST-SCR/CATALYTIC OXIDIZER
AND GAS CLEANING SYSTEMS

PROCESS & INSTRUMENTATION DIAGRAM
DIGESTER GAS FACILITIES
GAS DRYING UNIT

PLC NO. 15GCOMP

PROJECT NO. J–79

DRAWING NO. 15E-NP-210

19 of 20

GAS CLEANING VESSEL

15ETNK480

DRIP TRAP

15EEXR360
GAS/GAS EXCHANGER

15EEXR365
CHILLED WATER/GAS

15EEXR350
EXCHANGER

CONDENSER

COMPRESSOR

15EDRY350
GAS DRYING UNIT
REFRIGERATED

GAS DRYING UNIT SYSTEM ALARM PKG REFRIG

TEMP HI GAS DRYER OUTLET

LOW FLOW ALARM CH WATER

THERMAL DISPERSION

CALIBRATION GAS

VENT

PURGE HOA HI FLOW

CORRECTED NH3 SLIP FROM CEMS PANEL

NOx OUT FROM CEMS PANEL

NOx IN FROM CEMS PANEL

UREA FLOW TO CEMS PANEL

UMBILICAL WITH SAMPLE, CAL GAS AND PURGE

UMBILICAL TO CEMS PANEL

160211001 16E-NP-120 INTERCOOLER R/S 0160

16BSWI262

LIT 262
LE 262
LI 262

16BTNK260 UREA TANK

16BCV260 16BBV260 UREA FEED 2"UREA-STL 2"

16BBV262A 3"UREA-STL VENT 1"
DRAIN TO CONTAINMENT AREA

RECIRCULATING LOOP

1/2"UREA-STL

16BBV261C 1/2" 16BFLT261A 16BBV261B 16BBV261D 1/2" 16BBV261E

16BBV262 1/2" 16BBV260A 16BBV261 1/2" 16BFLT261 1/2" 16BBV261A 1/2" 1" x 1/2" 1/2" 1" x 1/2"

1/2"UREA-STL

16BFCP260 UREA INJECTION PANEL NOTE 5

AIR SUPPLY 80 PSI MIN 16BBV260B 1/2" 1/2"IA-STL

PURGE WATER SUPPLY 16BBV260C 1/2" 1/2"POTW-STL 16BBV260G 1/2"

LEVEL 120VAC UREA FLOW NOx IN NOx OUT CORRECTED NH3 SLIP

120VAC UPS

NOx INLET PROBE

30"EXH-STL 24" x 30"

ATM

PDI 486 FT 496 SE 483 16BCMP480 TURBO TE 485

TE 481 NOTE 3 VT 482 ZSH 484

PCV 429 PI 429A PI 429 I/P 429 FY 429B
FY 429A
FY 429

IA IA

160212004 16E-NP-120 EXHAUST BYPASS
160212003 16E-NP-120 EXHAUST MANIFOLD

160211002 16E-NP-120 INTERCOOLER L/S

1/4"IA-STL 1/4"UREA-STL

16BBV260F 1/4" 16BBV260E 1/4" AIR UREA

NOTE 7 16BBV260D 1/2"

TI 258 TE 258 16BBV254C 16BBV254B PDT 254 16BBV254A 16BBV254 TI 256 TE 256

TI 257 TE 257 16BBV253C 16BBV253B PDT 253 16BBV253A 16BBV253 TI 255 TE 255

160211006 16E-NP-130 EXH HEAT RECOVERY BOILER NOTE 4 30" x 36" 36"EXH-STL

16BBV252A 16BBV252C 3/4" 16BCLST252 SCR SCR CATALYST 16BBV252 36"EXH-STL

16BBV251A 3/4" 16BBV251C 16BCLST251 OXI OXIDATION CATALYST 16BBV251 3/4"

3/8" 16BBV252A 3/8" 16BBV252
3/8" 16BBV251A 3/8" 16BBV251

ENGINE LOAD ENGINE CALL CORRECTED NH3 SLIP

16BENG400 ENGINE 1

160213009 16E-NP-130 TURBO JACKET WATER NOTE 6

16BBV494 16BBV493

POST TURBO EXHAUST TMP TI 485
TURBO SPD SI 483
TURBO DRAIN TMP TI 481

TURBO THRUST BEARING ZAH 484
TURBO LUBE OIL PAL 492
TURBO OVERSPEED SAH 483
TURBO VAH 482

VSH 482

NOTE 2 16BFCP001

PDSL 492 PT 494 PT 493

INTERCLR H2O IN TEMP TMP TI 488
INTERCLR H2O OUT TEMP TMP TI 491

TURBO INLET PRS PI 494
TURBO DISCH PRS PI 493

NOTES:

1. UNLESS OTHERWISE NOTED ALL TAGGED ITEMS SHALL HAVE PREFIX "16B".

2. SEE 16B-NP-120 FOR PROCESS INDICATION.

3. 16BVT-482 IS MOUNTED ON TURBO MOUNTING BRACKET.

4. REFER TO DRAWING M1010 FOR EXTENT OF DUCTWORK.

5. UREA PUMPS LOCATED IN UREA INJECTION PANEL.

6. SAMPLE PORT WITH BALL VALVE AND PLUG (TYP. OF 4).

7. DRIP SHIELD AND DRAIN VALVE BY CONTRACTOR.

DESIGNED BY:	ZOMORODI, S. – 1/11
DRAWN BY:	RIVAS, A. – 1/11
CHECKED BY:	last, First – Date

LINE IS 2 INCHES AT FULL SIZE (IF NOT 2"-SCALE ACCORDINGLY)

MALCOLM PIRNIE

ORANGE COUNTY SANITATION DISTRICT

PLANT NO.1-PILOT TEST-SCR/CATALYTIC OXIDIZER AND GAS CLEANING SYSTEMS

PROCESS & INSTRUMENTATION DIAGRAM ENGINE AND EXHAUST FLOW WITH SCR/OXI CAT

PLC NO. XX
PROJECT NO. J-79
DRAWING NO. 16B-NP-110
20 of 20

MARK DESCRIPTION DATE APPR.

APPENDIX A-3:

Technical Memorandum:
Comparison of Digester Gas Sampling Method for Speciated Siloxanes

Date: July 13, 2011

To: File

From: Kit Liang, Malcolm Pirnie, WHI; Daniel Stepner, Malcolm Pirnie, WHI

Re: OCSD Cat Ox/SCR Pilot Study: Comparison of Digester Gas Sampling
            Method for Speciated Siloxanes

Project No.:   0788-187

Project Background

The Orange County Sanitation District (OCSD) requested pilot testing of a catalytic
oxidizer/selective catalytic reduction (Cat Ox/SCR) system for controlling air toxics and
priority pollutants from the Central Generation Systems (CGS) engines to meet February
2008 South Coast Air Quality Management District (SCAQMD) amendments to Rule
1110.2. The amendments to Rule 1110.2 included changes to the existing limits of 36
ppm to 11 ppm of oxides of nitrogen (NOx), 250 ppm to 30 ppm of volatile organic
compounds (VOCs), and 2000 to 250 ppm of carbon monoxide (CO) at 15% O_2. The Cat
Ox/SCR system reduces NOx, CO and VOC (i.e., formaldehyde, acrolein, etc.) emissions
from IC engine exhaust.

The pilot testing project took place at Plant No. 1 on Engine No. 1 and included the
installation of a Cat Ox/SCR system on the engine exhaust. This technology has been
proven effective for controlling NOx, CO, and VOCs from combustion units burning
natural gas. However, fouling or rapid performance degradation of the catalytic oxidizers
has been an issue for engines burning digester gas. Typically, digester gas fuel contains
contaminants such as volatile methyl-siloxanes and sulfurous compounds that tend to foul
the catalytic oxidizers. Therefore, Malcolm Pirnie proposed a scope of work for a pilot
test to verify the performance of the Cat Ox/SCR system with a digester gas cleaning
system (DGCS). Based on the pilot testing performed at Plant No. 2 Engine No. 3 in
2007, the DGCS proved successful in removing contaminants such as siloxanes and
hydrogen sulfide from the digester gas such that the catalyst performance is comparable
to that of an internal combustion (IC) engine operating on natural gas.

Identification of Digester Gas Sampling Methods

The purpose of the digester gas cleaning system is to remove siloxanes and any potential
contaminants, such as hydrogen sulfides in the digester gas, that can potentially foul or
reduce the performance of the Cat Ox/SCR system. There are two sampling methods that
are commonly used for measuring siloxanes: gas chromatography-mass spectrometry
(GC/MS) or wet chemistry method. Digester gas analyzed using GC/MS can be collected
using either Tedlar® bags or SUMMA canisters. The wet chemistry method requires
samples to be collected using methanol impingers over a two to four hour sampling

period, and then sent to a lab for analysis. After discussions with several certified laboratories, and review of several published papers, samples collected using Tedlar®, SUMMA canister or methanol impingers each has advantages and disadvantages based on the speciated siloxanes in the digester gas. However, collection of the samples using Tedlar® bags provides the most flexibility for minimum sampling time and equipment required.

As part of the Monitoring Test Procedure, the initial performance testing of the gas cleaning system collected samples using Tedlar® bags, SUMMA canister and methanol impinger methods at the digester gas inlet location during the same day and compared the analytical results to determine the most appropriate method for monitoring media breakthrough. The initial performance testing was performed by Malcolm Pirnie, except where noted. The following information was collected for the digester gas cleaning system test:

- Tedlar® bag collection at the DGCS inlet – Malcolm Pirnie collected and sent samples to a certified laboratory to test for speciated siloxanes, speciated VOCs using TO-15, total reduced sulfide using TO-15 and overall gas components and quality (%CH_4, %CO_2, %N_2, heating value) using EPA Method 3C.
- SUMMA canister collection at the DGCS inlet – Malcolm Pirnie collected and sent samples to a certified laboratory to test for speciated siloxanes, speciated VOCs using TO-15, total reduced sulfide using ASTM D-5504, and overall gas components and quality (%CH_4, %CO_2, %N_2, heating value) using ASTM D-1946.
- Wet chemistry method at the DGCS inlet – Engine 1 was operated for five hours at actual operating conditions with the digester gas cleaning system for performance testing. The performance test was performed for a continuous period of at least five hours (1 hour for stabilization and 4 hours for testing). During the test, individual measurements of inlet total siloxane, D4, D5, hexamethyl-disiloxane, octamethyltrisiloxane and any other siloxane compounds identifiable according to the test method was monitored and recorded.

Information obtained from the initial performance testing was used to select the most appropriate sampling method for the determining breakthrough and change-out.

Summary of Results

On March 16, 2010, digester gas was collected at the Plant 1 DGCS using the three sampling methods described above. Table 1 shows a summary of sampling results.

Table 1
Summary Comparison of Sampling Methods

OCSD Plant 1	Total Siloxane (ppbv)
Tedlar® – Inlet	3,584
SUMMA Canister – Inlet	546
Methanol Impinger – Inlet	1,457

Selection of the Sampling Method

The primary focus of the digester gas testing is to analyze for siloxane compounds. These compounds are most likely to foul the catalytic oxidizer catalyst. Of the three testing methods, the Tedlar® bag method resulted in the highest concentration of siloxanes. Siloxanes can be lost if a sample degrades. It is believed that the Tedlar® bag method provides a conservative estimate of siloxanes in the gas sample. The Tedlar® bag method also requires the least set-up and sampling time as well as the least equipment required. Although these were not the main criteria for selecting the sampling methods, they are benefits to using this method. When breakthrough of the carbon media is suspected, it is important to take a gas sample quickly to minimize potential fouling of the catalyst or downtime of the engine.

Based on the data presented above, the Tedlar® bag collection method was selected. Tedlar® bags provided the highest reported concentration of siloxanes and also provided the flexibility to test for VOCs and sulfurous compounds.

Conclusion

On March 16, 2010, digester gas was sampled at the inlet of the Plant 1 DGCS using three different methods: Tedlar® bags, SUMMA canisters, and methanol impingers. The gas samples collected using Tedlar® bags and SUMMA canisters were analyzed using GC/MS and the gas sample collected using methanol impingers was analyzed using the wet chemistry method. As shown in the summary of the results in Table 1, the Tedlar® bag sampling method detected the highest level of total siloxane. In addition, the Tedlar® bag sampling method provides the most flexibility of what compounds could be tested for and the minimum sampling time and equipment required. Based on these criteria, the Tedlar® bag method was chosen as the sampling method for future digester gas sampling.

APPENDIX A-4:

Technical Memorandum:
OCSD Catalytic Oxidizer/SCR Pilot Study:
SCR Urea Injection Mapping

Technical Memorandum

Date: July 13, 2011

To: File

From: Kit Liang, Malcolm Pirnie, WHI; Daniel Stepner, Malcolm Pirnie, WHI

Re: OCSD Cat Ox/SCR Pilot Study: Urea Injection Mapping

Project No.: 0788-187

Project Background

To meet the South Coast Air Quality Management District (SCAQMD) Rule 1110.2 limit for oxides of nitrogen (NOx), the Orange County Sanitation District (OCSD) installed a selective catalytic reduction (SCR) system with urea injection was installed in the internal combustion (IC) engine exhaust duct after a catalytic oxidizer (Cat Ox) (both systems supplied by Johnson Matthey) on Engine 1 at Plant 1. Under Amended Rule 1110.2, NOx exhaust levels have a lower limit of 11 ppmv for biogas-fueled engines effective July 30, 2011. The SCR system was designed to remove NOx through a chemical reaction between the NOx in the engine exhaust and ammonia (provided by urea spray injected into the exhaust gas stream upstream of the SCR) on the surface of the SCR catalyst. The urea injection rate is selected ("mapped") based on engine load and outlet NOx concentration (related to the blend of digester gas and natural gas supplement used by the engines at Plant 1). This memorandum outlines the methodology developed to control the urea injection rate.

SCR Urea Control System

The function of the SCR control system is to balance urea injection rate to reduce NOx exhaust concentration without emitting excess ammonia in the post-control exhaust gas. The excess ammonia that passes through the SCR catalyst unreacted is, known as "ammonia slip." Ammonia slip occurs when too much ammonia, or in this case urea, is injected into the exhaust stream, when the temperature of the gas is too low for the ammonia to react, or when the catalyst is degraded. The Research Permit for the pilot study has a maximum allowable ammonia slip of 10 ppm at the stack exhaust.   In addition to the unwanted emissions of ammonia from the stack exhaust, excess ammonia in the system can potentially cause damage to the heat recovery boiler and other equipment downstream from the SCR catalyst.

The control system determines the correct rate of urea injection according to the engine load signal, and this urea injection rate versus *engine load map* is programmed into the control system. The load map during the pilot testing period included 16 set points, and was programmed during commissioning by the system vendor, Johnson Matthey. This controller was able to interpolate between the tested load values to generate an overall curve of urea injection rate versus engine load. Thus, as the engine is brought to a load,

and as the engine load changes, the urea flow rate is adjusted by a flow control valve based on the monitored engine load.

In addition to the load map control, the injection system also uses a system of bias set points to more finely control, or "trim", the urea injection rate. The "NOx curve bias" is a percentage that can be input by the operator to increase or decrease the urea injection rate. This bias is typically set to 0%, but can be modified if engine operation is expected to change the NOx produced in the exhaust emissions. "NOx-add bias" increases the urea injection rate setting (in terms of gallon per hour, gph) based on the NOx outlet concentration recorded by the stack exhaust CEMS analyzer. When the NOx outlet concentration reaches the level set by the control system, the urea injection rate will increase by the selected bias set point. Conversely, "NOx-subtract bias" decreases the urea injection rate in the same manner based on the NOx outlet concentration.

As the engine ran under varying loads during the load mapping procedure, Johnson Matthey measured NOx with a portable chemiluminescent analyzer, and ammonia slip with Draeger® tubes at the SCR catalyst outlet. The purpose of this was to develop a urea injection versus engine load map that met NOx and ammonia slip emissions requirements.

The initial load mapping performed by Johnson Matthey on April 1, 2010 is provided below in Table 1 and in Figure 1. The solid line in Figure 1 represents the set points for urea injection based on engine load. The dashed line represents the urea injection rate with the upper NOx-add bias that increases urea injection based on the NOx outlet emissions. Note that the bias is set for a lower and upper value of NOx outlet concentration. In the case of the April 1, 2010 set points, when the NOx outlet concentration reached the NOx lower add bias concentration (8 ppm), urea injection would increase by an additional 0.50 gph. If the NOx outlet concentration continued to increase and reached the NOx upper add bias concentration (10 ppm), the urea injection would increase by an additional 0.90 ppm).

For the pilot testing period, a NOx-subtract bias was not set. A NOx-subtract bias would be used if the OCSD desired to keep the NOx outlet concentration above a threshold level. This could be set if there was a concern that urea would be over injected at low NOx outlet concentrations, causing ammonia slip issues. In the case of the pilot test, there was no desired lower NOx limit and no observed ammonia slip issues.

Table 1:

SCR Urea Injection Set Points at Commissioning (April 1, 2010)

Set Point	Engine Load (%)	Urea Injection Rate (gph)
1	0	0.00
2	10	0.27
3	20	0.28
4	30	0.29
5	40	0.30
6	50	0.31
7	60	0.32
8	70	0.36
9	80	0.38
10	90	0.40
11	95	0.45
12	100	0.48
13	105	0.57
14	110	0.58
15	115	0.60
16	120	0.80
NOx Bias Set Point	**NOx Outlet Concentration (ppmv)**	**Bias (gph)**
NOx curve bias	-	0%
NOx lower add bias	8	0.50
NOx upper add bias	10	0.90
NOx lower subtract bias	0	0.00
NOx upper subtract bias	0	0.00

Figure 1:

SCR Urea Injection Curve During Commissioning
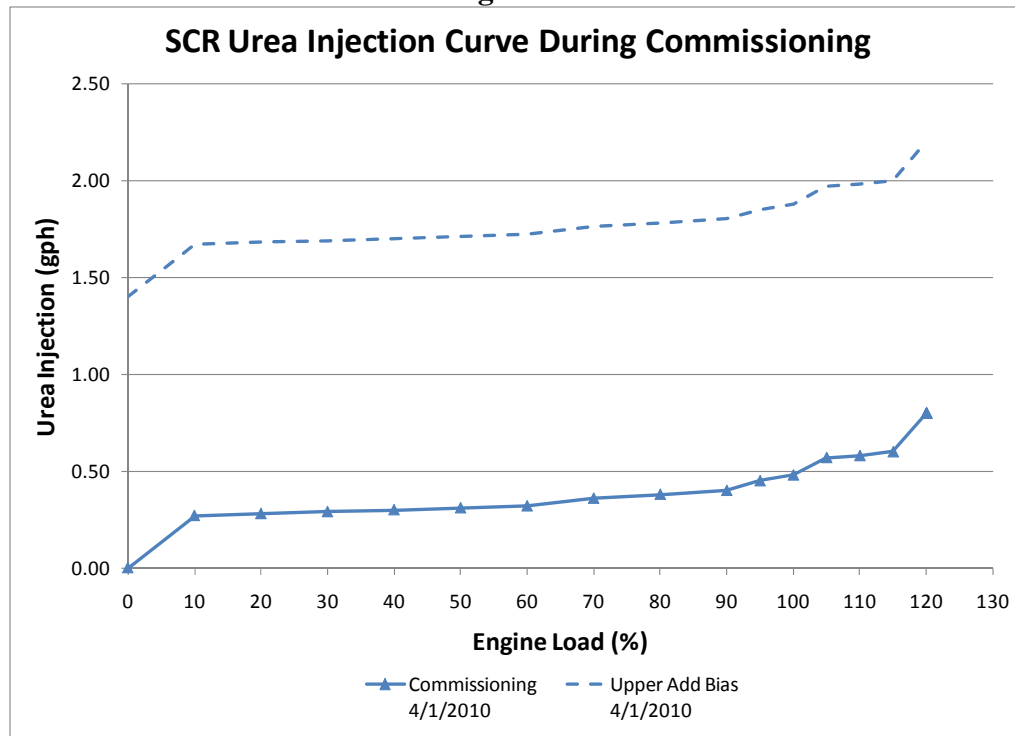
Urea Injection Set Point Adjustments During the Pilot Testing

During the pilot testing, Johnson Matthey made adjustments to the urea injection set points to refine control of the NOx emissions. On May 13, 2010, the urea injection NOx-add bias set points were decreased. The original NOx-add biases increased the urea injection rates by 0.50 and 0.90 gph when the NOx outlet concentrations hit 8 and 10 ppmv, respectively. Based on these set points, when the NOx outlet concentration reached the level set for the NOx-add bias, it was found that the system injected too much urea, so that the NOx outlet concentration was lowered too quickly, resulting in rapid fluctuations in the NOx outlet concentration. Therefore, the lower and upper NOx-add bias set points were set to 0.05 and 0.09 gph when the NOx outlet concentration reached 5 and 7 ppmv, respectively. With lower NOx-add bias set points, the maximum amount of urea injected (urea injection rate plus NO lower and upper add bias) was decreased. Therefore, the risk of not injecting enough urea to compensate for the NOx outlet concentration was increased. As a precautionary measure, the urea injection rate versus engine load set points were also increased slightly.

On June 8, 2010, the urea injection set points were readjusted. At the request of OCSD, the urea injection rate versus engine load set points were decreased to reduce possible ammonia slip resulting from over-injection of urea. This was a potential concern because the Plant 1 Engine 1 operates primarily on a greater than 95% digester gas to natural gas fuel ratio. The original set points were set higher to allow for a higher percentage of natural gas in the fuel, which in turn creates a higher NOx concentration in the engine exhaust. One additional set point was added at an engine load of 85% to further refine the engine load range. The set points programmed into the SCR control system on June 8, 2010 ran for the remaining pilot testing period through the end of March 2011. The effectiveness of these set points is discussed in the pilot testing report. A summary of the urea injection rate set points through the pilot testing period is provided in Table 2 and Figure 2.

OCSD Cat Ox/SCR Pilot Study:　　　　　　　　　　　　July 13, 2011
Urea Injection Mapping　　　　　　　　　　　　　　　Page 5 of 6

Table 2:

SCR Urea Injection Set Points During the Pilot Testing

Load/Urea Injection Set Point	Commissioning 4/1/2010		5/13/2010		6/8/2010	
	Engine Load (%)	Urea Injection (gph)	Engine Load (%)	Urea Injection (gph)	Engine Load (%)	Urea Injection (gph)
1	0	0.00	0	0.00	0	0.00
2	10	0.27	10	0.30	10	0.30
3	20	0.28	20	0.32	20	0.31
4	30	0.29	30	0.34	30	0.32
5	40	0.30	40	0.35	40	0.33
6	50	0.31	50	0.38	50	0.34
7	60	0.32	60	0.40	60	0.35
8	70	0.36	70	0.45	70	0.36
9	80	0.38	80	0.55	80	0.37
10	90	0.40	90	0.65	85	0.38
11	95	0.45	95	0.68	90	0.45
12	100	0.48	100	0.72	95	0.48
13	105	0.57	105	0.74	100	0.53
14	110	0.58	110	0.75	105	0.54
15	115	0.60	115	0.77	110	0.55
16	120	0.80	120	0.80	115	0.60
17	-	-	-	-	120	0.60
NOx Bias Set Point	NOx Outlet Concentration (ppmv)	Bias (gph)	NOx Outlet Concentration (ppmv)	Bias (gph)	NOx Outlet Concentration (ppmv)	Bias (gph)
NOx curve bias	-	0%	-	0%	-	0%
NOx lower add bias	8	0.50	5	0.05	5	0.05
NOx upper add bias	10	0.90	7	0.09	7	0.09
NOx lower subtract bias	0	0.00	0	0.00	0	0.00
NOx upper subtract bias	0	0.00	0	0.00	0	0.00

Figure 2:

SCR Urea Injection Curve During Pilot Testing
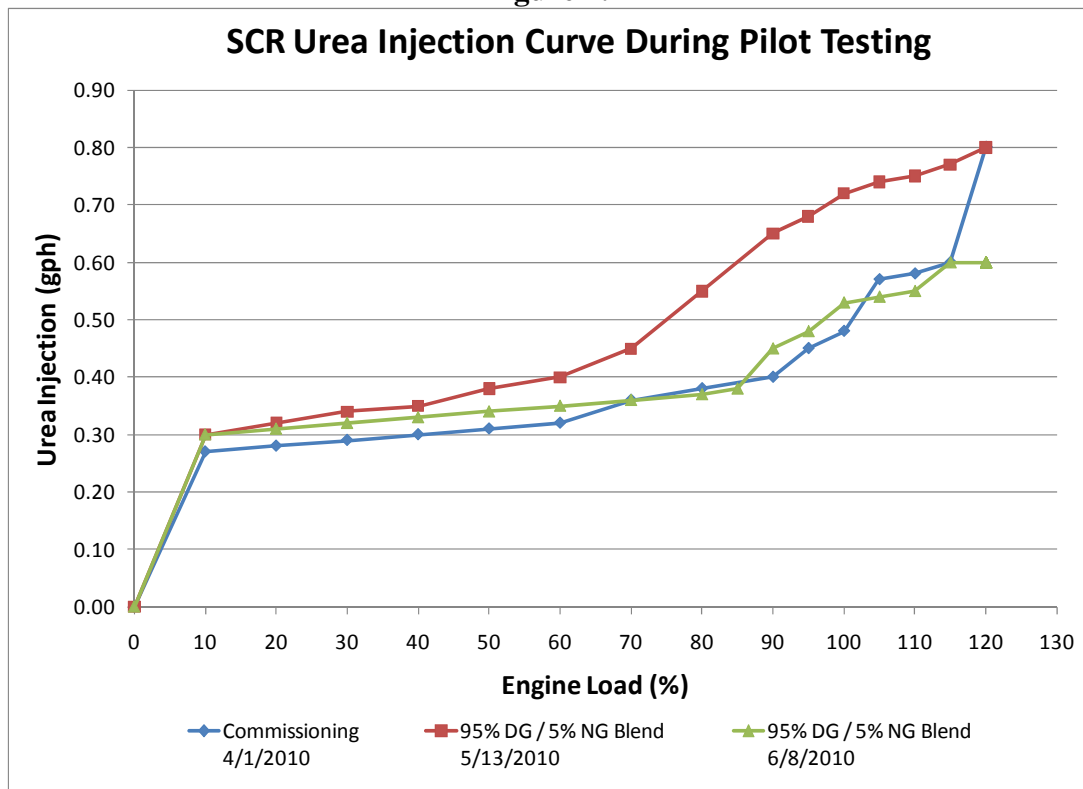
Limitations of the Urea Injection Mapping

Based on previous source testing data, the NOx concentration in the exhaust gas is higher when combusting natural gas than when combusting digester gas at a given load; therefore, there is a potential for variation in the NOx concentration at the inlet to the SCR system at a given load due to the varying fuel blend in biogas-fueled engines. Since the urea injection rate can only be established based on engine load and outlet NOx concentration, and not inlet NOx concentration, it is difficult to maintain a targeted NOx limit at the stack exhaust using this type of SCR system for fuel blend engines..

Conclusions and Recommendations

The urea injection set points were originally set during system commissioning on April 1, 2010 and were later readjusted on May 13, 2010 to refine NOx reduction in the engine exhaust gas. The urea injection set points were readjusted for a final time during the pilot test on June 8, 2010 for analysis of the SCR system.

Attachment:
Johnson Matthey Commissioning Report, June 1, 2010

Commissioning Report

Johnson Matthey
Catalysts

Date: 6/1/2010

Malcolm Pirnie / Orange County Sanitation District
Oxidation Catalyst and SCR Emission Control System
System Location: Orange County, CA

Prepared for:
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Written by:
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The SCR and Oxidation catalyst system at the Orange County Sanitation District is designed to control NOx, hydrocarbon, and CO emissions from a Cooper Model LSVB-12-SGC engine. The required reduction rates are shown in Table 1: Emissions Data (ppmVD @ 15% O_2). The reduction rates are guaranteed based on a 15 min average value per South Coast AQMD rule 1110.2.

Table 1: Emissions Data (ppmVD @ 15% O_2)

Exhaust Component	Catalyst Inlet (max)	Catalyst Outlet (max)*	Reduction Guaranteed
NOx	50 ppm	9 ppm	82.0%
VOC	120 ppm	25 ppm	79.2%
CO	800 ppm	100 ppm	87.5%
HCHO	60 ppm	9 ppm	85.0%
Ammonia Slip	---	10 ppm	---

The SCR system is designed to accommodate changes in the fuel usage of the LSVB-12-SGC engine. The fuel blend can range from 100% natural gas with 0% digester gas to 5% natural gas with 95% digester gas. Four engine load conditions were used for commissioning purposes to determine the necessary urea injection rates. The engine load values chosen were 60%, 80%, 100%, and 110% as this range includes the normal operating conditions of the engine. In addition to varying the engine load, the fuel ratio of natural gas to digester gas was set to one of three conditions to determine the necessary urea injection rates. The fuel ratio testing conditions starting with the most common include 5% natural gas with 95% digester gas, 50% natural gas with 50% digester gas, and 100% natural gas with 0% digester gas. Emission testing was performed for all of the resulting 12 conditions and recorded in Table 2: Emission Testing Results. The results show that the system successfully reduced CO and NOx emissions below the permit conditions while maintaining an NH3 slip of below 10 ppm.

Table 2: Emission Testing Results

SP	Gas Ratio	OCSD Engine Load %	JM & DL Engine Load %	Valve %	Urea Flow gph	CEMS NOX Corr 15%	Ecom NOX Corr 15%	NH3 Slip	CEMS CO Corr 15%	Ecom CO Corr 15%	Ecom Temp Post SCR	JM Temp Pre SCR	JM Temp Post SCR
1	50/50	110	100	63	0.63	6.7	8	0.5	8.8	6.9	746	755	756
2	50/50	100	95	63	0.63	6.7	8	0.5	10	8	759	762	773
3	50/50	80	72.5	58	0.4	3.8	6	0.2	9.4	7	775	800	786
4	50/50	60	59.1	57	0.34	4.4	4	0.1	8.9	7	761	820	796
5	100ng/0d	110	98.1	69	0.91	4.5	7	0	10.9	9	737	752	754
6	100ng/0d	100	92	67	0.76	4.5	6	0	11.4	9	749	757	761
7	100ng/0d	80	73.7	62	0.54	3.4	5	0	11.7	10	766	781	782
8	100ng/0d	60	58.1	58	0.38	3.6	5	0	9.9	8	755	807	784
9	5ng/95d	110	98.8	63	0.58	5.6	5	0	9.7	6	758	756	762
10	5ng/95d	100	95.5	63	0.57	3.1	4	0.1	8.6	7	779	776	787
11	5ng/95d	80	72.2	58	0.38	3.7	5	0	9.1	8	791	811	812
12	5ng/95d	60	60	55	0.33	1.2	1	0.1	9	8	783	830	815

A urea injection map was created based on the results of the testing outlined in Table 2. The urea injection map serves as the base or default urea injection rate at the corresponding engine load, see Table 3 – Load Map. To compensate for changing NOx concentrations due to fuel ratio fluctuations a bias value is added to or subtracted from the base urea set point. If the NOx concentration at the system outlet climbs to 7 ppm or higher an additional 0.05 gph of urea is injected to bring the NOx levels down. If the NOx concentration at the system outlet continues to rise to 9 ppm or higher an additional 0.09 gph of urea will be injected via the additional bias. The resulting amount of urea will be injected upstream of the SCR catalyst to properly control NOx across all fuel ratios.

Table 3: Load Map / Base Urea Set points and Bias

Engine Load %	Urea Set point (gal/min)	Initial High Bias 7 ppm NOx (gal/min)	Additional High Bias 9 ppm NOx (gal/min)	Initial Low Bias x ppm NOx (gal/min)	Additional Low Bias x ppm NOx (gal/min)
0	0	+0.05	+0.09	0	0
10	0.30	+0.05	+0.09	0	0
20	0.31	+0.05	+0.09	0	0
30	0.32	+0.05	+0.09	0	0
40	0.33	+0.05	+0.09	0	0
50	0.34	+0.05	+0.09	0	0
60	0.35	+0.05	+0.09	0	0
70	0.36	+0.05	+0.09	0	0
80	0.37	+0.05	+0.09	0	0
90	0.45	+0.05	+0.09	0	0
95	0.48	+0.05	+0.09	0	0
100	0.53	+0.05	+0.09	0	0
105	0.54	+0.05	+0.09	0	0
110	0.55	+0.05	+0.09	0	0
115	0.60	+0.05	+0.09	0	0
120	0.60	+0.05	+0.09	0	0

The load map urea set points were determined based on the most common operating condition, which is a high concentration of digester gas (approximately 95% digester gas and 5% natural gas). It was determined during testing that adding natural gas to the fuel blend increased the NOx concentration in the exhaust stream. For this reason, the baseline urea set points coincide with the 95% digester gas and 5% natural gas fuel ratio condition which is the most common and requires the least amount of urea injection. The low bias was disabled for this application because the base urea set points correspond to the minimum urea flow requirements.

Some of the challenges of this control system include the 80 second delay between the time the exhaust gas concentrations change the moment the corresponding NOx concentration signal is received from the CEMS. This lagging indication of NOx concentration, which is used by the control system to determine

if additional urea should be injected via the bias, causes an oscillation in the injection rate when the engine is running at high natural gas concentrations. At the lower and more common natural gas concentrations the system is more stable. These oscillations alone are not enough to bring the system out of compliance because the performance is based on a 15 minute average. The system is capable of being tuned to have an acceptable 15 minute average performance over all operating conditions. The second challenge is the fluctuation of the engine load signal. The engine load signal fluctuates very rapidly (a couple times per second) in a range of plus or minus 10%. The urea injection cabinet uses this signal to control the base urea injection set point. This engine load signal fluctuation causes an inherent fluctuation in the base urea injection rate although it is dampened somewhat by a PID loop.

The following is a table including all SCR system set points at the time of commissioning, see Table 4: System Set points. These set points are for informational purposes and should not be changed without the approval of Johnson Matthey.

Table 4: System Set Points

Component Description

Urea Heat Control system:	JM P&ID Reference	Set Point	Initiates Purge	Description
Control SP	TT-0301	40*F	No	Urea heater activates 5 DegF below this setpoint and de-activates 5 DegF above this setpoint
Temp Low SP	TT-0301	30*F	No	Alarms if this temperature is met indicating Urea heater circuit failure
System Time Delays:				
Air/Water Purge Time Delay	SV-0103	15 sec.	No	Timer for water purge prior to standard air purge
Engine Time Delay	CP-1001	100 sec.	No	Times out any alarms upon startup until system is fully operational
Kick-Start Timer	CV-0501	45 sec.	No	Opens Control Valve CV-0501 to 100% upon injection to fill feed line
Purge Time Delay	FS-1501	45 sec.	No	Timer to initiate redundant pump
Heater SP Time Delay	TT-0301	NA	No	Time delay to initiate urea heater
Fill Rate Time Delay	NA	NA	No	Time delay to initiate transfer pump
Flow Alarm Time Delay	FT-0401	4.5sec.	Yes	Time delay to initiate low flow alarm
System Operation:				
Air Pressure Main	PR-0602	100 psig	No	System air pressure main
Air Pressure Switch SP	PS-1601	30 psig	Yes	System purge and alarms when air pressure drops below this setpoint
Air Pressure to Injection Module	PR-0603	30 psig	No	Injection Module operational pressure
Cat Pre-Temp High AL	TT-0302	900F	No	Alarms if this temperature is met
Injection Temp SP	TT-0302	600F	No	Turns on injection at 10 DegF above this sp and turns off 10 Degf below this setpoint
Load/Urea SP	CP-1001	Startup	No	Load to Urea setpoint set during startup
Low Load SP	ELS-1901	10%	Yes	Urea will not be injected below this load
Load Deadband	ELS-1901	0%	Yes	Urea pump activates 5% above low load setpoint and de-activates 5% below setpoint
Low Tank Level	LT-1201	10%	Yes	Alarms below this setpoint, injection will not occur to prevent dry pump
Low Urea Flow	FT-0401	0.1	Yes	Alarms if urea flow during injection drops below this setpoint
Reagent Supply Pressure	PR-0601	100 psig	No	Urea supply pressure
Stop Air SP	NA	300 sec	No	Injection Module purges for this amount of time after system shuts down.
Urea High PSI SP	PT-0201	160 psig	No	Alarms when urea pressure is above this setpoint
Urea Low Flow SP	FS-1501	0.10 gph	Yes*	Initiates redundant pump when below this setpoint
Urea Low PSI SP	PT-0201	20 psig	No	Alarms when urea pressure is below this setpoint
Post Urea PSI	PT-0202	-	No	This pressure sensor is for monitoring and diagnostical reference only.
CAT Diff PSI		5psig	No	Alarms when the differential pressure across the catalysts exceeds this value.
Load, Urea Setpoints Main:				
Flowmeter Max Scale	FT-0401	3.0 gph	No	Maximum Scale of Urea Flow Transmitter
Air/Water Purge Time Delay	SV-0103	15 sec.	No	Timer for water purge prior to standard air purge
Calibration Screen:				
Engine Load- mA in Max	ELS-1901	20	N/A	Max mA signal received from engine relative to load
Engine Load- mA in Min	ELS-1901	3.98	N/A	Min mA signal received from engine relative to load
Engine Load- Max Scale	ELS-1901	110	N/A	Load that correlates to receiving a 20mA signal
Engine Load- Min Scale	ELS-1901	0	N/A	Load that correlates to receiving a 4mA signal
Urea Scale	FT-0401	99.6	N/A	Utilized for scaling flow transmitter at initial commissioning
Tank Scale Upper	LT-1201	100	N/A	Utilized for scaling level transmitter at initial commissioning
Tank Scale Lower	LT-1201	19.9	N/A	Utilized for scaling level transmitter at initial commissioning
PID Screen:				
Proportional Setting- P	CV-0501	750	N/A	Proportional Setting for CV-0501
Integral Setting- I	CV-0501	0.025	N/A	Integral Setting for CV-0501

SP=Set Point
* Initiates Purge when second pump does not activate switch

APPENDIX B-1:

Fixed Gas Sampling Summary

Fixed Gas Sampling Summary
Plant 1 - Digester Gas Cleaning System

Collection Date	Lab	Collection Method	Carbon Dioxide		Methane		Nitrogen		Oxygen	
			Inlet	Outlet	Inlet	Outlet	Inlet	Outlet	Inlet	Outlet
			(%)	(%)	(%)	(%)	(%)	(%)	(%)	(%)
3/16/2010	Centek	Tedlar Bag	33.4	32.4	55.2	54.9	1.1	1.7	0.3	0.5
4/7/2010	Centek	Tedlar Bag	27.0	27.6	53.7	62.5	1.6	1.7	0.6	0.8
4/29/2010	Centek	Tedlar Bag	28.5	31.4	62.6	59.5	2.0	1.7	0.5	0.5
5/19/2010	Centek (1)	Tedlar Bag	19.1	24.6	44.4	55.3	27.0	13.2	7.1	3.3
5/27/2010	Centek	Tedlar Bag	31.4	31.0	54.0	54.3	4.0	1.1	1.2	0.5
6/11/2010	Centek	Tedlar Bag	25.5	23.1	56.3	45.0	1.4	1.5	0.5	0.5
6/29/2010	Centek (2)	Tedlar Bag	40.1	34.5	58.3	48.4	4.0	16.0	1.1	4.3
8/12/2010	AccuLabs, Inc. (3)	Summa Canister	0.3	0.3	0.5	0.5	77.5	77.9	21.3	20.5
8/12/2010	AtmAA Inc.	Tedlar Bag	36.6	36.4	61.0	60.9	1.0	1.2	0.3	0.3
8/19/2010	AccuLabs, Inc. (4)	Tedlar Bag	31.2	15.7	63.9	32.3	1.9	45.7	0.5	5.4
8/19/2010	AccuLabs, Inc. (4)	Summa Canister	31.7	25.8	65.8	60.4	0.8	10.8	0.1	0.7
9/1/2010	AtmAA Inc.	Tedlar Bag	35.0	35.7	60.4	60.6	2.5	1.9	0.5	0.4
9/15/2010	AtmAA Inc.	Tedlar Bag	36.6	36.6	60.5	60.6	1.3	1.6	0.2	0.3
9/20/2010	AtmAA Inc.	Tedlar Bag	36.2	36.4	60.8	60.7	1.2	1.2	0.3	0.3
11/4/2010	AtmAA Inc.	Tedlar Bag	35.9	N/A	59.9	N/A	2.6	N/A	0.6	N/A
1/12/2011	AtmAA Inc.	Tedlar Bag	34.0	N/A	59.0	N/A	5.1	N/A	1.4	N/A
2/9/2011	AtmAA Inc.	Tedlar Bag	37.7	37.2	60.4	60.7	0.9	1.1	0.1	0.1
2/24/2011	AtmAA Inc.	Tedlar Bag	36.6	N/A	60.1	N/A	1.9	N/A	0.2	N/A
Minimum			25.5	23.1	53.7	45.0	0.9	1.1	0.1	0.1
Maximum			40.1	37.2	62.6	62.5	5.1	1.9	1.4	0.8
Average			33.9	32.8	58.7	58.0	2.2	1.5	0.6	0.4

Notes:
(1) Inlet and outlet sample results from 5/19/10 are not accurate due to an error in collection, indicated by high nitrogen composition (>5%), and are not included in the minimum, maximum and average.
(2) Outlet sample results from 6/29/10 are not accurate due to an error in collection, indicated by high nitrogen composition (>5%), and are not included in the minimum, maximum and average.
(3) Inlet and outlet sample results from AccuLabs on 8/12/10 are not accurate due to an error in collection, indicated by high nitrogen composition (>5%), and are not included in the minimum, maximum and average.
(4) Sample results from 8/19/10 are not consistent with sample results from other laboratories and are concluded to be erroneous and not included in the minimum, maximum and average.
(5) N/A indicates not applicable because the compound was not analyzed for.

APPENDIX B-2:

Total Reduced Sulfide Summary

Total Reduced Sulfide Summary
Plant 1 - Digester Gas Cleaning System

Collection Date	Lab (1)	Collection Method	Hydrogen Sulfide				Carbonyl Sulfide				Methyl Mercaptan				Ethyl Mercaptan			
			Inlet		Outlet		Inlet		Outlet		Inlet		Outlet		Inlet		Outlet	
			Rpt Lmt	Amt	Rpt Lmt	Amt	Rpt Lmt	Amt	Rpt Lmt	Amt	Rpt Lmt	Amt	Rpt Lmt	Amt	Rpt Lmt	Amt	Rpt Lmt	Amt
			(ppbv)	(ppbv)	(ppbv)	(ppbv)	(ppbv)	(ppbv)	(ppbv)	(ppbv)	(ppbv)	(ppbv)	(ppbv)	(ppbv)	(ppbv)	(ppbv)	(ppbv)	(ppbv)
4/21/2010	OCSD	AQMD 307-91	1,000	25,700	25	ND	6	20	6	ND	12	70	12	ND	19	225	19	ND
5/11/2010	OCSD	AQMD 307-91	2,500	31,700	25	263	6	20	6	8	12	53	12	ND	19	263	19	ND
6/8/2010	OCSD	AQMD 307-91	630	27,970	63	2,162	5	16	5	ND	3	49	3	ND	4	272	4	ND
6/22/2010	OCSD	AQMD 307-91	630	21,620	6	ND	5	14	5	ND	3	54	3	ND	4	301	4	ND
7/7/2010	OCSD	AQMD 307-91	630	28,570	6	ND	5	13	5	ND	3	57	3	ND	4	265	4	ND
7/21/2010	OCSD	AQMD 307-91	630	24,870	6	ND	5	10	5	ND	3	48	3	ND	4	272	4	ND
8/3/2010	OCSD	AQMD 307-91	630	27,450	6	ND	5	19	5	12	3	58	3	ND	4	293	4	ND
8/12/2010	OCSD	AQMD 307-91	630	28,190	6	ND	5	22	5	18	3	72	3	ND	4	304	4	ND
8/12/2010	AccuLabs, Inc. (2)	Summa Canister	5	<MDL	5	<MDL	2	<MDL	2	<MDL	2	<MDL	2	<MDL	2	<MDL	2	<MDL
8/12/2010	AtmAA Inc.	Tedlar Bag	500	30,700	200	<MDL	200	<MDL	200	<MDL	200	<MDL	200	<MDL	200	<MDL	200	<MDL
8/19/2010	AccuLabs, Inc. (3)	Tedlar Bag	100	14,600	10	<MDL	5	13	5	<MDL	20	181	5	<MDL	20	470	5	<MDL
8/19/2010	AccuLabs, Inc. (3)	Summa Canister	100	14,100	10	<MDL	5	13	5	<MDL	20	191	5	<MDL	20	478	5	<MDL
9/1/2010	OCSD	AQMD 307-91	630	14,690	6	ND	5	28	5	15	3	81	3	ND	4	301	4	ND
9/14/2010	OCSD	AQMD 307-91	630	23,010	6	545	5	17	5	17	3	62	3	ND	4	258	4	ND
1/25/2011	OCSD	AQMD 307-91	630	28,540	6	ND	5	28	5	16	3	61	3	ND	4	189	4	ND
2/9/2011	OCSD	AQMD 307-91	630	31,870	6	1,755	5	21	5	18	3	79	3	ND	4	210	4	ND
2/23/2011	OCSD	AQMD 307-91	630	24,460	6	ND	5	15	5	ND	3	58	3	ND	4	205	4	ND
Minimum			N/A	14,690	N/A	263	N/A	10	N/A	8	N/A	48	N/A	ND	N/A	189	N/A	ND
Maximum			N/A	31,870	N/A	2,162	N/A	28	N/A	18	N/A	81	N/A	ND	N/A	304	N/A	ND
Average			N/A	26,381	N/A	1,181	N/A	19	N/A	15	N/A	62	N/A	ND	N/A	258	N/A	ND

Notes:

(1) Hydrogen sulfide results from Centek are above the operating range of the instrument and appear to be erroneous. Centek sample results are not included in the analysis of this pilot testing program.

(2) Inlet and outlet sample results from AccuLabs on 8/12/10 are not accurate due to an error in collection, indicated by high nitrogen composition (>5%), and are not included in the minimum, maximum and average.

(3) Sample results from 8/19/10 are not consistent with sample results from other laboratories and are concluded to be erroneous and not included in the minimum, maximum and average.

(4) N/A indicates not applicable or that the compound was not analyzed for.

(5) ND indicates non-detect.

(6) <MDL indicates that the result, if any, was less than the method detection limit.

July 2011

Total Reduced Sulfide Summary
Plant 1 - Digester Gas Cleaning System

Collection Date	Lab (1)	Collection Method	Dimethyl Sulfide				Carbon Disulfide				n-Propyl Thiol				iso-Propyl Thiol			
			Inlet		Outlet		Inlet		Outlet		Inlet		Outlet		Inlet		Outlet	
			Rpt Lmt	Amt	Rpt Lmt	Amt	Rpt Lmt	Amt	Rpt Lmt	Amt	Rpt Lmt	Amt	Rpt Lmt	Amt	Rpt Lmt	Amt	Rpt Lmt	Amt
			(ppbv)	(ppbv)	(ppbv)	(ppbv)	(ppbv)	(ppbv)	(ppbv)	(ppbv)	(ppbv)	(ppbv)	(ppbv)	(ppbv)	(ppbv)	(ppbv)	(ppbv)	(ppbv)
4/21/2010	OCSD	AQMD 307-91	18	ND	18	ND	13	ND	13	ND	21	584	21	ND	30	310	30	ND
5/11/2010	OCSD	AQMD 307-91	18	ND	18	ND	13	ND	13	ND	21	630	21	ND	30	360	30	ND
6/8/2010	OCSD	AQMD 307-91	5	8	5	10	3	4	3	3	320	536	3	ND	3	341	3	4
6/22/2010	OCSD	AQMD 307-91	5	6	5	ND	3	ND	3	ND	3	679	3	ND	3	406	3	ND
7/7/2010	OCSD	AQMD 307-91	5	12	5	ND	3	ND	3	ND	3	625	3	ND	3	381	3	ND
7/21/2010	OCSD	AQMD 307-91	5	8	5	12	3	ND	3	4	3	593	3	ND	3	373	3	ND
8/3/2010	OCSD	AQMD 307-91	5	13	5	12	3	ND	3	6	3	622	3	ND	3	401	3	ND
8/12/2010	OCSD	AQMD 307-91	5	17	5	20	3	ND	3	7	3	649	3	ND	3	416	3	ND
8/12/2010	AccuLabs, Inc. (2)	Summa Canister	2	15	2	11	2	5	2	4	2	<MDL	2	<MDL	2	<MDL	2	<MDL
8/12/2010	AtmAA Inc.	Tedlar Bag	200	<MDL	200	<MDL	200	<MDL	200	<MDL	320	<MDL	200	<MDL	250	<MDL	200	<MDL
8/19/2010	AccuLabs, Inc. (3)	Tedlar Bag	5	10	5	8	5	<MDL	5	<MDL	50	1,180	5	<MDL	5	<MDL	5	<MDL
8/19/2010	AccuLabs, Inc. (3)	Summa Canister	5	10	5	9	5	<MDL	5	2	50	1,190	5	<MDL	5	<MDL	5	<MDL
9/1/2010	OCSD	AQMD 307-91	5	13	5	18	3	9	3	12	3	565	3	ND	3	416	3	ND
9/14/2010	OCSD	AQMD 307-91	5	15	5	18	3	ND	3	7	3	631	3	ND	3	341	3	ND
1/25/2011	OCSD	AQMD 307-91	5	8	5	11	3	5	3	8	3	454	3	ND	3	214	3	ND
2/9/2011	OCSD	AQMD 307-91	5	14	5	ND	3	ND	3	6	3	514	3	ND	3	242	3	ND
2/23/2011	OCSD	AQMD 307-91	5	13	5	ND	3	ND	3	ND	3	476	3	ND	3	268	3	ND
Minimum			N/A	6	N/A	10	N/A	4	N/A	3	N/A	454	N/A	ND	N/A	214	N/A	4
Maximum			N/A	17	N/A	20	N/A	9	N/A	12	N/A	679	N/A	ND	N/A	416	N/A	4
Average			N/A	12	N/A	14	N/A	6	N/A	7	N/A	581	N/A	ND	N/A	344	N/A	4

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Total Reduced Sulfide Summary
Plant 1 - Digester Gas Cleaning System

Collection Date	Lab (1)	Collection Method	Dimethyl Disulfide				Isopropyl Mercaptan				n-Propyl Mercaptan			
			Inlet		Outlet		Inlet		Outlet		Inlet		Outlet	
			Rpt Lmt (ppbv)	Amt (ppbv)	Rpt Lmt (ppbv)	Amt (ppbv)	Rpt Lmt (ppbv)	Amt (ppbv)	Rpt Lmt (ppbv)	Amt (ppbv)	Rpt Lmt (ppbv)	Amt (ppbv)	Rpt Lmt (ppbv)	Amt (ppbv)
4/21/2010	OCSD	AQMD 307-91	30	ND	30	ND	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
5/11/2010	OCSD	AQMD 307-91	30	ND	30	ND	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
6/8/2010	OCSD	AQMD 307-91	4	ND	4	ND	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
6/22/2010	OCSD	AQMD 307-91	4	ND	4	ND	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
7/7/2010	OCSD	AQMD 307-91	4	ND	4	ND	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
7/21/2010	OCSD	AQMD 307-91	4	ND	4	ND	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
8/3/2010	OCSD	AQMD 307-91	4	ND	4	ND	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
8/12/2010	OCSD	AQMD 307-91	4	ND	4	ND	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
8/12/2010	AccuLabs, Inc. (2)	Summa Canister	5	<MDL	5	<MDL	5	<2	5	<2	5	<2	5	<2
8/12/2010	AtmAA Inc.	Tedlar Bag	200	<MDL	200	<MDL	0.2	250	0.2	<MDL	0.2	320	0.2	<MDL
8/19/2010	AccuLabs, Inc. (3)	Tedlar Bag	5	<MDL	5	<MDL	5	<2	5	<2	50	1,180	5	<2
8/19/2010	AccuLabs, Inc. (3)	Summa Canister	5	<MDL	5	<MDL	5	<2	5	<2	50	1,190	5	<2
9/1/2010	OCSD	AQMD 307-91	4	ND	4	ND	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
9/14/2010	OCSD	AQMD 307-91	4	ND	4	ND	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
1/25/2011	OCSD	AQMD 307-91	4	ND	4	ND	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2/9/2011	OCSD	AQMD 307-91	4	ND	4	ND	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2/23/2011	OCSD	AQMD 307-91	4	ND	4	ND	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Minimum			N/A	ND	N/A	ND	N/A	250	N/A	ND	N/A	320	N/A	ND
Maximum			N/A	ND	N/A	ND	N/A	250	N/A	ND	N/A	320	N/A	ND
Average			N/A	ND	N/A	ND	N/A	250	N/A	ND	N/A	320	N/A	ND

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APPENDIX B-3:

Speciated Siloxane Sampling Detailed Summary

Siloxane Sampling Summary
Plant 1 - Digester Gas Cleaning System

Collection Date	Lab	Collection Method	Hexamethyldisiloxane (L2)				Hexamethylcyclotrisiloxane (D3)				Octamethyltrisiloxane (L3)				Octamethylcyclotetrasiloxane (D4)			
			Inlet		Outlet		Inlet		Outlet		Inlet		Outlet		Inlet		Outlet	
			Rpt Lmt (ppbv)	Amt (ppbv)	Rpt Lmt (ppbv)	Amt (ppbv)	Rpt Lmt (ppbv)	Amt (ppbv)	Rpt Lmt (ppbv)	Amt (ppbv)	Rpt Lmt (ppbv)	Amt (ppbv)	Rpt Lmt (ppbv)	Amt (ppbv)	Rpt Lmt (ppbv)	Amt (ppbv)	Rpt Lmt (ppbv)	Amt (ppbv)
3/16/2010	Centek	Tedlar Bag	20	ND	20	ND	20	10	20	ND	20	12	20	ND	20	600	20	ND
4/7/2010	Centek	Tedlar Bag	20	ND	10	ND	20	9.7	10	ND	20	11	10	ND	20	840	10	ND
4/29/2010	Centek	Tedlar Bag	50	ND	10	ND	50	ND	10	ND	50	10	10	ND	50	1600	10	ND
5/19/2010	Centek (1)	Tedlar Bag	20	ND	10	ND	20	15	10	ND	20	17	10	ND	20	810	10	7.6
5/27/2010	Centek	Tedlar Bag	20	ND	10	8.4	20	13	10	ND	20	17	10	0.1	20	1300	10	5.2
5/27/2010	Centek	Methanol Impinger	20	N/A	10	ND	20	N/A	10	ND	20	N/A	10	ND	20	369	10	ND
6/11/2010	Centek	Tedlar Bag	20	ND	10	7.4	20	12	10	12	20	15	10	ND	20	660	10	200
6/29/2010	Centek (2)	Tedlar Bag	20	ND	10	ND	20	17	10	ND	20	19	10	ND	20	620	10	ND
8/12/2010	AccuLabs (3)	Summa Canister	0.025	3.12	0.025	2.98	0.025	<0.01	0.025	<0.01	0.025	<0.01	0.025	<0.01	0.025	<0.01	0.025	<0.01
8/12/2010	AtmAA	Tedlar Bag	N/A	ND	N/A	ND	N/A	ND	N/A	ND	N/A	ND	N/A	ND	N/A	471	N/A	ND
8/19/2010	AccuLabs (4)	Tedlar Bag	0.025	1.61	0.025	0.26	0.025	4.84	0.025	0.03	0.025	4.97	0.025	ND	0.025	41.5	0.025	0.03
8/19/2010	AccuLabs (4)	Summa Canister	0.025	1.34	0.025	0.23	0.025	5.62	0.025	0.03	0.025	5.84	0.025	ND	0.025	43.1	0.025	0.03
9/1/2010	AtmAA	Tedlar Bag	60	<MDL	60	<MDL	60	<MDL	60	<MDL	60	<MDL	60	<MDL	60	510	60	<MDL
9/15/2010	AtmAA	Tedlar Bag	60	<MDL	60	<MDL	60	<MDL	60	<MDL	60	<MDL	60	<MDL	60	860	60	<MDL
9/20/2010	AtmAA	Tedlar Bag	60	<MDL	60	<MDL	60	<MDL	60	<MDL	60	<MDL	60	<MDL	60	864	60	<MDL
11/4/2010	AtmAA	Tedlar Bag	60	<MDL	N/A	N/A	60	<MDL	N/A	N/A	60	<MDL	N/A	N/A	60	597	N/A	N/A
1/12/2011	AtmAA	Tedlar Bag	60	<MDL	N/A	N/A	60	<MDL	N/A	N/A	60	<MDL	N/A	N/A	60	409	N/A	N/A
2/9/2011	AtmAA	Tedlar Bag	60	<MDL	60	<MDL	60	<MDL	60	<MDL	60	<MDL	60	<MDL	60	420	60	<MDL
2/24/2011	AtmAA	Tedlar Bag	60	<MDL	N/A	N/A	60	<MDL	N/A	N/A	60	<MDL	N/A	N/A	60	438	N/A	N/A
Minimum			N/A	<MDL	N/A	7.4	N/A	9.7	N/A	12.0	N/A	10.0	N/A	0.1	N/A	369	N/A	5.2
Maximum			N/A	<MDL	N/A	8.4	N/A	17.0	N/A	12.0	N/A	19.0	N/A	0.1	N/A	1,600	N/A	200.0
Average			N/A	<MDL	N/A	7.9	N/A	12.3	N/A	12.0	N/A	14.0	N/A	0.1	N/A	704	N/A	102.6

Notes:

(1) Inlet and outlet sample results from 5/19/10 are not accurate due to an error in collection, indicated by high nitrogen composition (>5%), and are not included in the minimum, maximum and average.

(2) Outlet sample results from 6/29/10 are not accurate due to an error in collection, indicated by high nitrogen composition (>5%), and are not included in the minimum, maximum and average.

(3) Inlet and outlet sample results from AccuLabs on 8/12/10 are not accurate due to an error in collection, indicated by high nitrogen composition (>5%), and are not included in the minimum, maximum and average.

(4) Sample results from 8/19/10 are not consistent with sample results from other laboratories and are concluded to be erroneous and not included in the minimum, maximum and average.

(5) N/A indicates not applicable or that the compound was not analyzed for.

(6) ND indicates non-detect.

(7) <MDL indicates that the result, if any, was less than the method detection limit.

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Siloxane Sampling Summary
Plant 1 - Digester Gas Cleaning System

Collection Date	Lab	Collection Method	Decamethyltetrasiloxane (L4)				Decamethylcyclopentasiloxane (D5)				Total Siloxane	
			Inlet		Outlet		Inlet		Outlet		Inlet	Outlet
			Rpt Lmt (ppbv)	Amt (ppbv)	Rpt Lmt (ppbv)	Amt (ppbv)	Rpt Lmt (ppbv)	Amt (ppbv)	Rpt Lmt (ppbv)	Amt (ppbv)		
3/16/2010	Centek	Tedlar Bag	20	84	20	ND	20	2900	20	7.0	3,584.0	<MDL
4/7/2010	Centek	Tedlar Bag	20	170	10	ND	20	7500	10	8.8	8,510.0	<MDL
4/29/2010	Centek	Tedlar Bag	50	100	10	ND	50	14000	10	ND	15,700.0	ND
5/19/2010	Centek (1)	Tedlar Bag	20	83	10	ND	20	3500	10	ND	4,393.0	<MDL
5/27/2010	Centek	Tedlar Bag	20	73	10	0.22	20	1300	10	15	2,673.0	15.0
5/27/2010	Centek	Methanol Impinger	20	N/A	10	ND	20	2478	10	ND	2,847.0	ND
6/11/2010	Centek	Tedlar Bag	20	130	10	ND	20	7700	10	36	8,490.0	248.0
6/29/2010	Centek (2)	Tedlar Bag	20	170	10	ND	20	7900	10	39	8,690.0	39.0
8/12/2010	AccuLabs (3)	Summa Canister	0.025	<0.01	0.025	<0.01	0.025	<0.01	0.025	<0.01	3.1	3.0
8/12/2010	AtmAA	Tedlar Bag	N/A	ND	N/A	ND	N/A	3254	N/A	ND	3,725.0	ND
8/19/2010	AccuLabs (4)	Tedlar Bag	0.025	6.36	0.025	ND	0.03	860	0.03	ND	919.3	0.3
8/19/2010	AccuLabs (4)	Summa Canister	0.025	6.72	0.025	ND	0.1	908	0.025	ND	970.6	0.3
9/1/2010	AtmAA	Tedlar Bag	80	<MDL	80	<MDL	80	4058	80	<MDL	4,568.0	<0.4
9/15/2010	AtmAA	Tedlar Bag	80	<MDL	80	<MDL	80	3486	80	<MDL	4,346.0	<0.4
9/20/2010	AtmAA	Tedlar Bag	80	<MDL	80	<MDL	80	4862	80	<MDL	5,726.0	<0.4
11/4/2010	AtmAA	Tedlar Bag	80	<MDL	N/A	N/A	80	4632	N/A	N/A	5,229.0	N/A
1/12/2011	AtmAA	Tedlar Bag	80	<MDL	N/A	N/A	80	6140	N/A	N/A	6,549.0	N/A
2/9/2011	AtmAA	Tedlar Bag	80	<MDL	80	<MDL	80	4160	80	<MDL	4,580.0	<MDL
2/24/2011	AtmAA	Tedlar Bag	80	<MDL	N/A	N/A	80	6200	N/A	N/A	6,638.0	N/A
Minimum			N/A	73	N/A	0.2	N/A	1,300	N/A	7.0	919	0.3
Maximum			N/A	170	N/A	0.2	N/A	14,000	N/A	36.0	15,700	248.0
Average			N/A	121	N/A	0.2	N/A	5,371	N/A	16.7	5,452	60.5

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APPENDIX B-4:

Volatile Organic Compound Summary

VOC Data Summary
Plant 1 - Digester Gas Cleaning System

Analyte	3/16/2010 Centek				3/16/2010 AccuLabs (Summa Canister)		4/7/2010 Centek				4/29/2010 Centek			
	Inlet (ppbv)		Outlet (ppbv)		Inlet (ppbv)		Inlet (ppbv)		Outlet (ppbv)		Inlet (ppbv)		Outlet (ppbv)	
	Rpt Lmt	Amt	Rpt Lmt	Amt	Rpt Lmt	Amt	Rpt Lmt	Amt	Rpt Lmt	Amt	Rpt Lmt	Amt	Rpt Lmt	Amt
Acetone	40	ND	40	40	2.5	<2.5	40	ND	20	17	100	63	20	15
Benzene	20	13	20	ND	0.5	9.25	20	8.2	10	ND	50	10	10	ND
Carbon Disulfide	20	ND	20	ND	0.5	0.97	20	ND	10	3.4	50	ND	10	5
Chlorobenzene	20	ND	20	ND	0.5	<0.21	20	ND	10	ND	50	ND	10	ND
Cyclohexane	20	ND	20	ND	0.5	2.94	20	18	10	ND	50	22	10	ND
1,2-Dichlorobenzene	20	ND	20	ND	0.5	0.33	20	ND	10	ND	50	ND	10	ND
1,4-Dichlorobenzene	20	5	20	ND	0.5	12.6	20	ND	10	ND	50	28	10	ND
cis-1,2-Dichloroethene	20	35	20	4.3	0.5	30.6	20	23	10	ND	50	45	10	12
trans-1,2-Dichloroethene	20	ND	20	ND	0.5	<0.20	20	ND	10	ND	50	ND	10	ND
Ethanol	N/A	N/A	N/A	N/A	1.0	<0.37	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Ethyl Acetate	40	ND	40	ND	1.0	<0.45	40	ND	20	ND	100	ND	20	ND
Ethylbenzene	20	37	20	ND	0.5	33.4	20	44	10	ND	50	100	10	ND
4-Ethyltoluene	20	20	20	ND	0.5	14.7	20	21	10	ND	50	43	10	ND
Freon 11	20	ND	20	ND	N/A	N/A	20	ND	10	ND	50	ND	10	2.9
n-Heptane	20	73	20	ND	0.5	55.9	20	75	10	ND	50	100	10	ND
Hexane	20	ND	20	ND	0.5	80.2	20	88	10	ND	50	210	10	ND
Isopropyl Alcohol	20	ND	20	300	N/A	N/A	20	ND	10	30	50	ND	10	13
Methylene Chloride	20	7.7	20	ND	2.5	7.63	20	5.2	10	3.8	50	12	10	5.2
Methyl Isobutyl Ketone (MIBK)	40	ND	40	ND	2.0	<0.57	40	ND	20		100	ND	20	ND
2-Propanol (IPA)	N/A	N/A	N/A	N/A	1.0	4.05	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Propene	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Propylene	20	ND	20	ND	5.0	2140	20	ND	10	ND	50	ND	10	ND
Styrene	20	4.7	20	ND	0.5	5.65	20	4.2	10	ND	50	19	10	ND
Tetrachloroethene (PCE)	N/A	N/A	N/A	N/A	0.5	5.16	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Tetrachloroethylene	20	8.2	20	ND	N/A	N/A	20	ND	10	ND	50	ND	10	ND
Toluene	20	1200	20	ND	5.0	1350	20	1300	10	4.1	50	1600	10	ND
1,2,4-Trichlorobenzene	20	ND	20	ND	0.5	<0.26	20	ND	10	ND	50	ND	10	ND
Trichloroethene (TCE)	20	12	20	11	0.5	7.26	20	9.6	10	ND	50	14	10	ND
Trichloroethylene	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Trichlorofluoromethane(F-11)	N/A	N/A	N/A	N/A	2.0	2.36	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
1,2,4-Trimethylbenzene	20	76	20	ND	0.5	110	20	70	10	ND	50	240	10	ND
1,3,5-Trimethylbenzene	20	33	20	ND	0.5	38.5	20	30	10	ND	50	88	10	ND
2,2,4-Trimethylpentane	20	27	20	ND	N/A	N/A	20	66	10	ND	50	65	10	ND
Vinyl Chloride	20	ND	20	ND	0.5	2.39	20	ND	10	ND	50	ND	10	ND
m & p-Xylene	40	69	40	ND	1.0	76.8	40	76	20	ND	100	100	20	ND
o-Xylene	20	24	20	ND	0.5	27.9	20	26	10	ND	50	41	10	ND
Total VOCs	N/A	1,594	N/A	340	N/A	4,019	N/A	1,819	N/A	30	N/A	2,403	N/A	25

Notes:

(1) Inlet and outlet sample results from 5/19/10 are not accurate due to an error in collection, indicated by high nitrogen composition (>5%), and are not included in the minimum, maximum and average.

(2) Outlet sample results from 6/29/10 are not accurate due to an error in collection, indicated by high nitrogen composition (>5%), and are not included in the minimum, maximum and average.

(3) Inlet and outlet sample results from AccuLabs on 8/12/10 are not accurate due to an error in collection, indicated by high nitrogen composition (>5%), and are not included in the minimum, maximum and average.

(4) Sample results from 8/19/10 are not consistent with sample results from other laboratories and are concluded to be erroneous and not included in the minimum, maximum and average.

(5) N/A indicates not applicable or that the compound was not analyzed for.

(6) ND indicates non-detect.

(7) <MDL indicates that the result, if any, was less than the method detection limit.

Analyte	5/11/2010 OCSD				5/19/2010 Centek (1)				5/25/2010 OCSD				5/27/2010 Centek			
	Inlet (ppbv)		Outlet (ppbv)		Inlet (ppbv)		Outlet (ppbv)		Inlet (ppbv)		Outlet (ppbv)		Inlet (ppbv)		Outlet (ppbv)	
	Rpt Lmt	Amt	Rpt Lmt	Amt	Rpt Lmt	Amt	Rpt Lmt	Amt	Rpt Lmt	Amt	Rpt Lmt	Amt	Rpt Lmt	Amt	Rpt Lmt	Amt
Acetone	4.300	7.24	4.640	7.01	40	ND	20	45	4.640	10.2	4.300	9.67	40	ND	20	ND
Benzene	3.900	9.53	4.210	ND	20	22	10	11	4.210	9.28	3.900	ND	20	9.8	10	4.1
Carbon Disulfide	6.280	ND	6.780	ND	20	9.8	10	21	6.780	ND	6.280	ND	20	ND	10	3.5
Chlorobenzene	3.780	4.57	4.080	ND	20	9.6	10	ND	4.080	5.85	3.780	ND	20	ND	10	ND
Cyclohexane	3.820	ND	4.130	ND	20	33	10	12	4.130	ND	3.820	ND	20	12	10	6.5
1,2-Dichlorobenzene	3.520	ND	3.810	ND	20	ND	10	ND	3.810	ND	3.520	ND	20	ND	10	ND
1,4-Dichlorobenzene	3.580	20.8	3.860	ND	20	47	10	ND	3.860	26.8	3.580	ND	20	5.3	10	ND
cis-1,2-Dichloroethene	3.080	37.7	3.320	17.1	20	360	10	54	3.320	103	3.080	72.4	20	80	10	63
trans-1,2-Dichloroethene	3.680	ND	3.970	ND	20	32	10	4.4	3.970	ND	3.680	3.71	20	ND	10	5.8
Ethanol	4.300	ND	4.640	ND	N/A	N/A	N/A	N/A	4.640	ND	4.300	ND	N/A	N/A	N/A	N/A
Ethyl Acetate	5.450	ND	5.890	ND	40	ND	20	ND	5.890	ND	5.450	ND	40	ND	20	4.3
Ethylbenzene	3.380	85.4	3.640	ND	20	250	10	2.6	3.640	141	3.380	ND	20	96	10	7.8
4-Ethyltoluene	3.000	59.3	3.240	ND	20	65	10	ND	3.240	51.1	3.000	ND	20	16	10	ND
Freon 11	N/A	N/A	N/A	N/A	20	ND	10	5.1	N/A	N/A	N/A	N/A	20	6.3	10	4.8
n-Heptane	3.080	83.8	3.320	ND	20	210	10	3	3.320	87.2	3.080	41.8	20	76	10	36
Hexane	3.620	37	3.920	ND	20	200	10	47	3.920	36.6	3.620	9.55	20	150	10	27
Isopropyl Alcohol	2.950	ND	3.190	ND	20	ND	10	27	3.190	ND	2.950	ND	20	ND	10	ND
Methylene Chloride	5.220	ND	5.640	ND	20	9	10	9.4	5.640	ND	5.220	ND	20	8.2	10	7.3
Methyl Isobutyl Ketone (MIBK)	2.950	ND	3.190	ND	40	ND	20	ND	3.190	ND	2.950	ND	40	ND	20	ND
2-Propanol (IPA)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Propene	44.600	3270	48.800	3480	N/A	N/A	N/A	N/A	49.300	3130	45.400	3470	N/A	N/A	N/A	N/A
Propylene	N/A	N/A	N/A	N/A	20	ND	10	ND	N/A	N/A	N/A	N/A	20	ND	10	ND
Styrene	2.080	7.92	2.240	ND	20	49	10	ND	2.240	24.7	2.080	ND	20	13	10	4.3
Tetrachloroethene (PCE)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Tetrachloroethylene	3.350	ND	3.620	ND	20	370	10	ND	3.620	ND	3.350	6.56	20	6	10	4.2
Toluene	23.600	1340	2.560	ND	20	2700	10	25	26.000	2010	23.900	1030	50	1200	20	360
1,2,4-Trichlorobenzene	2.600	ND	2.810	ND	20	ND	10	ND	2.810	ND	2.600	ND	20	ND	10	ND
Trichloroethene (TCE)	N/A	N/A	N/A	N/A	20	610	10	22	N/A	N/A	N/A	N/A	20	14	10	7.6
Trichloroethylene	3.520	9.67	3.810	ND	N/A	N/A	N/A	N/A	3.810	12.7	3.520	10.2	N/A	N/A	N/A	N/A
Trichlorofluoromethane(F-11)	7.120	ND	7.700	ND	N/A	N/A	N/A	N/A	7.700	ND	7.120	ND	N/A	N/A	N/A	N/A
1,2,4-Trimethylbenzene	3.300	178	3.560	ND	20	430	10	ND	3.560	188	3.300	ND	20	81	10	ND
1,3,5-Trimethylbenzene	4.100	77.1	4.430	ND	20	150	10	ND	4.430	76.2	4.100	ND	20	35	10	ND
2,2,4-Trimethylpentane	N/A	N/A	N/A	N/A	20	89	10	3.2	N/A	N/A	N/A	N/A	20	60	10	25
Vinyl Chloride	5.200	ND	5.620	ND	20	12	10	5.8	5.620	ND	5.200	6.81	20	ND	10	6.6
m & p-Xylene	4.220	103	4.560	ND	40	240	20	ND	4.560	88.5	4.220	ND	40	47	20	ND
o-Xylene	4.050	42.6	4.370	ND	20	91	10	ND	4.370	35.6	4.050	ND	20	20	10	ND
Total VOCs	**N/A**	**5,374**	**N/A**	**3,504**	**N/A**	**5,948**	**N/A**	**264**	**N/A**	**6,037**	**N/A**	**4,651**	**N/A**	**1,845**	**N/A**	**511**

VOC Data Summary
Plant 1 - Digester Gas Cleaning System

Analyte	6/8/2010 OCSD Inlet (ppbv) Rpt Lmt	Amt	Outlet (ppbv) Rpt Lmt	Amt	6/11/2010 Centek Inlet (ppbv) Rpt Lmt	Amt	Outlet (ppbv) Rpt Lmt	Amt	6/29/2010 Centek (2) Inlet (ppbv) Rpt Lmt	Amt	Outlet (ppbv) Rpt Lmt	Amt	7/7/2010 OCSD Inlet (ppbv) Rpt Lmt	Amt	Outlet (ppbv) Rpt Lmt	Amt
Acetone	4.470	ND	4.820	ND	40	ND	40	200	40	88	20	65	4.640	9.24	5.160	ND
Benzene	4.060	11	4.370	6.01	20	15	20	7.2	20	14	10	ND	4.210	7.34	4.680	ND
Carbon Disulfide	6.530	ND	7.030	ND	20	ND	20	5.8	20	ND	10	3.2	6.780	ND	7.530	ND
Chlorobenzene	3.930	ND	4.230	ND	20	5.9	20	ND	20	6.4	10	ND	4.080	ND	4.530	ND
Cyclohexane	3.980	ND	4.280	ND	20	ND	20	9.2	20	16	10	ND	4.130	ND	4.590	ND
1,2-Dichlorobenzene	3.670	ND	3.950	ND	20	ND	20	ND	20	ND	10	ND	3.810	ND	4.230	ND
1,4-Dichlorobenzene	3.720	19.2	4.000	ND	20	16	20	ND	20	17	10	ND	3.860	ND	4.290	ND
cis-1,2-Dichloroethene	3.200	37.6	3.440	59.6	20	42	20	55	20	44	10	ND	3.320	22.7	3.690	ND
trans-1,2-Dichloroethene	3.820	ND	4.120	ND	20	ND	20	ND	20	4.6	10	ND	3.970	ND	4.410	ND
Ethanol	4.470	ND	4.820	ND	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	4.640	ND	5.160	ND
Ethyl Acetate	5.670	ND	6.100	ND	40	ND	40	ND	40	ND	20	ND	5.890	ND	6.540	ND
Ethylbenzene	3.510	74.1	3.780	38.9	20	110	20	61	20	84	10	ND	3.640	62.4	4.050	ND
4-Ethyltoluene	3.120	68.6	3.360	ND	20	31	20	9	20	21	10	ND	3.240	28.8	3.600	ND
Freon 11	N/A	N/A	N/A	N/A	20	ND	20	5.9	20	5.2	10	3.5	N/A	N/A	N/A	N/A
n-Heptane	3.200	62.4	3.440	45.8	20	94	20	44	20	99	10	ND	3.320	79.1	3.690	ND
Hexane	3.770	33.7	4.060	26.6	20	130	20	35	20	160	10	3.2	3.920	35.6	4.350	ND
Isopropyl Alcohol	3.070	ND	3.300	ND	20	ND	20	ND	20	ND	10	ND	3.190	ND	3.540	ND
Methylene Chloride	5.430	ND	5.850	5.96	20	9.3	20	13	20	14	10	8.8	5.640	ND	6.270	6.38
Methyl Isobutyl Ketone (MIBK)	3.070	ND	3.300	ND	40	ND	40	ND	40	ND	20	ND	3.190	ND	3.540	ND
2-Propanol (IPA)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Propene	47.200	3630	49.900	4130	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	47.900	3270	53.800	3600
Propylene	N/A	N/A	N/A	N/A	20	ND	20	ND	20	ND	10	ND	N/A	N/A	N/A	N/A
Styrene	2.160	8.4	2.320	ND	20	23	20	6.2	20	15	10	2.6	2.240	7.18	2.490	ND
Tetrachloroethene (PCE)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Tetrachloroethylene	3.480	ND	3.750	11.5	20	21	20	7.5	20	13	10	ND	3.620	ND	4.020	ND
Toluene	24.900	3080	26.300	1400	20	3600	20	800	20	2000	10	3.7	25.300	2090	2.850	ND
1,2,4-Trichlorobenzene	2.700	ND	2.910	ND	20	ND	20	ND	20	9.2	10	ND	2.810	ND	3.120	ND
Trichloroethene (TCE)	N/A	N/A	N/A	N/A	20	28	20	16	20	17	10	ND	N/A	N/A	N/A	N/A
Trichloroethylene	3.670	6.24	3.950	12.3	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	3.810	7.14	4.230	ND
Trichlorofluoromethane(F-11)	7.410	ND	7.980	ND	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	7.700	ND	8.550	ND
1,2,4-Trimethylbenzene	3.430	117	3.700	ND	20	190	20	ND	20	120	10	ND	3.560	124	3.960	ND
1,3,5-Trimethylbenzene	4.260	38.4	4.590	ND	20	69	20	ND	20	44	10	ND	4.430	36.2	4.920	ND
2,2,4-Trimethylpentane	N/A	N/A	N/A	N/A	20	55	20	31	20	39	10	ND	N/A	N/A	N/A	N/A
Vinyl Chloride	5.410	ND	5.820	ND	20	ND	20	ND	20	ND	10	ND	5.620	ND	6.240	ND
m & p-Xylene	4.390	60.5	4.730	31.4	40	100	40	52	40	180	20	ND	4.560	111	5.070	7.90
o-Xylene	4.210	24.4	4.540	ND	20	42	20	10	20	64	10	ND	4.370	41.6	4.860	ND
Total VOCs	N/A	7,272	N/A	5,768	N/A	4,535	N/A	1,278	N/A	2,943	N/A	65	N/A	5,932	N/A	3,614

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Analyte	7/21/2010				8/3/2010				8/12/2010				8/12/2010			
	OCSD				OCSD				OCSD				AccuLabs, Inc. - Summa Canisters (3)			
	Inlet (ppbv)		Outlet (ppbv)		Inlet (ppbv)		Outlet (ppbv)		Inlet (ppbv)		Outlet (ppbv)		Inlet (ppbv)		Outlet (ppbv)	
	Rpt Lmt	Amt	Rpt Lmt	Amt	Rpt Lmt	Amt	Rpt Lmt	Amt	Rpt Lmt	Amt	Rpt Lmt	Amt	Rpt Lmt	Amt	Rpt Lmt	Amt
Acetone	4.300	6.97	4.820	12.7	4.640	17.7	4.990	13.8	4.820	10.7	4.640	13	N/A	N/A	N/A	N/A
Benzene	3.900	8.70	4.370	ND	4.210	10.9	4.520	ND	4.370	9.15	4.210	ND	N/A	N/A	N/A	N/A
Carbon Disulfide	6.280	ND	7.030	ND	7.280	ND	7.280	ND	7.030	ND	6.780	ND	N/A	N/A	N/A	N/A
Chlorobenzene	3.780	ND	4.230	ND	4.380	ND	4.380	ND	4.230	ND	4.080	ND	N/A	N/A	N/A	N/A
Cyclohexane	3.820	ND	4.280	ND	4.440	ND	4.440	ND	4.280	8.88	4.130	ND	N/A	N/A	N/A	N/A
1,2-Dichlorobenzene	3.520	ND	3.950	ND	4.090	ND	4.090	ND	3.950	ND	3.810	ND	N/A	N/A	N/A	N/A
1,4-Dichlorobenzene	3.580	ND	4.000	ND	4.150	ND	4.150	ND	4.000	ND	3.860	ND	N/A	N/A	N/A	N/A
cis-1,2-Dichloroethene	3.080	17.2	3.440	17.3	3.320	44.2	3.570	65.1	3.440	24.6	3.320	60.2	N/A	N/A	N/A	N/A
trans-1,2-Dichloroethene	3.680	ND	4.120	ND	4.260	ND	4.260	ND	4.120	ND	3.970	ND	N/A	N/A	N/A	N/A
Ethanol	4.300	ND	4.820	9.89	4.990	ND	4.990	5.52	4.820	ND	4.640	ND	N/A	N/A	N/A	N/A
Ethyl Acetate	5.450	ND	6.100	ND	6.320	ND	6.320	ND	6.100	ND	5.890	ND	N/A	N/A	N/A	N/A
Ethylbenzene	3.380	60.7	3.780	ND	3.640	50.2	3.920	4.07	3.780	52.8	3.640	ND	N/A	N/A	N/A	N/A
4-Ethyltoluene	3.000	34.2	3.360	ND	3.240	32.1	3.480	ND	3.360	26.3	3.240	ND	N/A	N/A	N/A	N/A
Freon 11	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
n-Heptane	3.080	84.1	3.440	ND	3.320	82.8	3.570	26.3	3.440	122	3.320	17.3	N/A	N/A	N/A	N/A
Hexane	3.620	40.5	4.060	13.8	3.920	48.4	4.200	21.4	4.060	65.1	3.920	26.8	N/A	N/A	N/A	N/A
Isopropyl Alcohol	2.950	ND	3.300	ND	3.420	ND	3.420	ND	3.300	ND	3.190	ND	N/A	N/A	N/A	N/A
Methylene Chloride	5.220	ND	5.850	9.52	5.640	5.87	6.060	ND	5.850	6.01	5.640	6.19	N/A	N/A	N/A	N/A
Methyl Isobutyl Ketone (MIBK)	2.950	ND	3.300	ND	3.420	ND	3.420	ND	3.300	ND	3.190	ND	N/A	N/A	N/A	N/A
2-Propanol (IPA)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Propene	45.200	3140	49.500	3540	48.100	3630	52.400	3590	50.400	3140	49.300	3600	N/A	N/A	N/A	N/A
Propylene	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Styrene	2.080	7.19	2.320	ND	2.240	4.95	2.410	ND	2.320	6.01	2.240	ND	N/A	N/A	N/A	N/A
Tetrachloroethene (PCE)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Tetrachloroethylene	3.350	ND	3.750	ND	3.620	26.3	3.890	ND	3.750	ND	3.620	ND	N/A	N/A	N/A	N/A
Toluene	23.800	2510	2.660	ND	25.400	2110	2.760	ND	26.600	2680	2.560	9.76	N/A	N/A	N/A	N/A
1,2,4-Trichlorobenzene	2.600	ND	2.910	ND	3.560	ND	3.020	ND	2.910	ND	2.810	ND	N/A	N/A	N/A	N/A
Trichloroethene (TCE)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Trichloroethylene	3.520	9.78	3.950	ND	3.810	22.9	4.090	5.67	3.950	12.8	3.810	5.21	N/A	N/A	N/A	N/A
Trichlorofluoromethane(F-11)	7.120	ND	7.980	ND	8.260	ND	8.260	ND	7.980	ND	7.700	ND	N/A	N/A	N/A	N/A
1,2,4-Trimethylbenzene	3.300	154	3.700	ND	3.560	121	3.830	ND	3.700	115	3.560	ND	N/A	N/A	N/A	N/A
1,3,5-Trimethylbenzene	4.100	45.8	4.590	ND	4.430	39.9	4.760	ND	4.590	39.6	4.430	ND	N/A	N/A	N/A	N/A
2,2,4-Trimethylpentane	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Vinyl Chloride	5.200	ND	5.820	ND	6.030	ND	6.030	ND	5.820	ND	5.620	ND	N/A	N/A	N/A	N/A
m & p-Xylene	4.220	110	4.730	ND	4.560	82.9	4.900	15.4	4.730	83.2	4.560	ND	N/A	N/A	N/A	N/A
o-Xylene	4.050	43.3	4.540	ND	4.370	33.4	4.700	ND	4.540	31.4	4.370	ND	N/A	N/A	N/A	N/A
Total VOCs	N/A	6,272	N/A	3,593	N/A	6,364	N/A	3,747	N/A	6,434	N/A	3,738	N/A	N/A	N/A	N/A

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VOC Data Summary
Plant 1 - Digester Gas Cleaning System

Analyte	8/12/2010 AtmAA Inc. - Tedlar Bags				8/19/2010 AccuLabs, Inc. - Tedlar Bags (4)				8/19/2010 AccuLabs, Inc. - Summa Canisters (4)				9/1/2010 OCSD			
	Inlet (ppbv)		Outlet (ppbv)		Inlet (ppbv)		Outlet (ppbv)		Inlet (ppbv)		Outlet (ppbv)		Inlet (ppbv)		Outlet (ppbv)	
	Rpt Lmt	Amt	Rpt Lmt	Amt	Rpt Lmt	Amt	Rpt Lmt	Amt	Rpt Lmt	Amt	Rpt Lmt	Amt	Rpt Lmt	Amt	Rpt Lmt	Amt
Acetone	N/A	79	N/A	42.2	2.5	62	2.5	33.7	2.5	27.3	2.5	20.5	4.640	11	4.640	14.9
Benzene	N/A	15.70	N/A	7.83	0.5	14.80	0.5	3.72	0.5	15.20	0.5	3.4	4.210	7.75	4.210	7.55
Carbon Disulfide	8	ND	8	ND	0.5	1.21	0.5	3.13	0.5	1.16	0.5	3.91	6.780	ND	6.780	9.3
Chlorobenzene	8	ND	8	ND	0.5	ND	0.5	ND	0.5	ND	0.5	ND	4.080	ND	4.080	ND
Cyclohexane	8	ND	8	ND	0.5	7.61	0.5	ND	0.5	7.82	0.5	1.72	4.130	ND	4.130	ND
1,2-Dichlorobenzene	6	ND	6	ND	0.5	ND	0.5	ND	0.5	ND	0.5	ND	3.810	ND	3.810	ND
1,4-Dichlorobenzene	6	8.32	6	ND	0.5	4.47	0.5	ND	0.5	10.8	0.5	ND	3.860	17.9	3.860	ND
cis-1,2-Dichloroethene	N/A	34.1	N/A	66.9	0.5	45.2	0.5	44.2	0.5	47.3	0.5	44.7	3.320	47.3	3.320	70.3
trans-1,2-Dichloroethene	8	ND	8	ND	0.5	ND	0.5	ND	0.5	ND	0.5	ND	3.970	ND	3.970	ND
Ethanol	N/A	N/A	N/A	N/A	1.0	ND	1.0	ND	1.0	ND	1.0	ND	4.640	ND	4.640	ND
Ethyl Acetate	N/A	22.2	N/A	15.3	1.0	ND	1.0	ND	1.0	ND	1.0	ND	5.890	ND	5.890	ND
Ethylbenzene	8	52.4	8	ND	0.5	54.2	0.5	1.85	0.5	59.7	0.5	1.2	3.640	73.2	3.640	ND
4-Ethyltoluene	8	64.1	8	ND	0.5	11.5	0.5	ND	0.5	14.9	0.5	1.3	3.240	12.7	3.240	ND
Freon 11	N/A	ND	N/A	ND	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
n-Heptane	8	ND	8	36.2	0.5	95.1	0.5	10.1	0.5	91.1	0.5	9.21	3.320	85.3	3.320	9.94
Hexane	N/A	97.9	N/A	44	0.5	90.1	0.5	10.2	0.5	89.5	0.5	9.9	3.920	52.1	3.920	33.4
Isopropyl Alcohol	12	ND	12	ND	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	3.190	ND	3.190	ND
Methylene Chloride	8	ND	8	ND	2.5	14.4	2.5	6.54	2.5	12.1	2.5	6.26	5.640	ND	5.640	ND
Methyl Isobutyl Ketone (MIBK)	N/A	N/A	N/A	N/A	2.0	5.91	2.0	ND	2.0	5.82	2.0	ND	3.190	ND	3.190	ND
2-Propanol (IPA)	N/A	N/A	N/A	N/A	1.0	ND	1.0	ND	1.0	ND	1.0	ND	N/A	N/A	N/A	N/A
Propene	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	101.000	3320	47.900	3980
Propylene	N/A	N/A	N/A	N/A	5.0	2910	5.0	1620	5.0	2870	5.0	1510	N/A	N/A	N/A	N/A
Styrene	8	ND	8	ND	0.5	4.96	0.5	ND	0.5	6.9	0.5	ND	2.240	12.9	2.240	ND
Tetrachloroethene (PCE)	6	11	6	ND	0.5	8.32	0.5	0.95	0.5	8.97	0.5	0.86	N/A	N/A	N/A	N/A
Tetrachloroethylene	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	3.620	6.64	3.620	ND
Toluene	N/A	1630	N/A	18.6	5.0	1430	0.5	42.7	5.0	1570	0.5	40.4	53.400	7300	2.560	287
1,2,4-Trichlorobenzene	8	ND	8	ND	0.5	ND	0.5	ND	0.5	ND	0.5	ND	2.810	ND	3.560	ND
Trichloroethene (TCE)	N/A	16.3	N/A	8.38	0.5	16.6	0.5	3.72	0.5	18.1	0.5	3.37	N/A	N/A	N/A	N/A
Trichloroethylene	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	3.810	9.21	3.810	10.6
Trichlorofluoromethane(F-11)	N/A	N/A	N/A	N/A	2.0	4.6	2.0	1.23	2.0	4.11	2.0	3.66	7.700	ND	7.700	ND
1,2,4-Trimethylbenzene	8	70.2	8	ND	0.5	38.5	0.5	1.57	0.5	56.7	0.5	6.49	3.560	67.1	3.560	ND
1,3,5-Trimethylbenzene	8	33	8	ND	0.5	18.8	0.5	0.44	0.5	23.9	0.5	1.82	4.430	34	4.430	ND
2,2,4-Trimethylpentane	8	ND	8	ND	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Vinyl Chloride	6	ND	6	ND	0.5	2.19	0.5	2.43	0.5	2.97	0.5	2.28	5.620	ND	5.620	ND
m & p-Xylene	8	91.6	8	ND	1.0	117	1.0	4.07	1.0	134	1.0	5.28	4.560	54.6	4.560	ND
o-Xylene	8	33.4	8	ND	0.5	40.2	0.5	2.19	0.5	45.6	0.5	2.48	4.370	21.6	4.370	ND
Total VOCs	**N/A**	**2,259**	**N/A**	**239**	**N/A**	**4,998**	**N/A**	**1,791**	**N/A**	**5,124**	**N/A**	**1,679**	**N/A**	**11,133**	**N/A**	**4,423**

VOC Data Summary
Plant 1 - Digester Gas Cleaning System

Analyte	9/14/2010 OCSD				1/13/2011 OCSD				2/9/2011 OCSD			
	Inlet (ppbv)		Outlet (ppbv)		Inlet (ppbv)		Outlet (ppbv)		Inlet (ppbv)		Outlet (ppbv)	
	Rpt Lmt	Amt	Rpt Lmt	Amt	Rpt Lmt	Amt	Rpt Lmt	Amt	Rpt Lmt	Amt	Rpt Lmt	Amt
Acetone	4.820	7.29	4.640	14.2	4.820	19.6	4.990	15.2	4.820	8.69	4.640	ND
Benzene	4.370	10.40	4.210	23	4.370	12.10	4.520	5.57	4.370	11.40	4.210	ND
Carbon Disulfide	7.030	ND	6.780	7.22	7.030	ND	7.280	ND	7.030	ND	6.780	ND
Chlorobenzene	4.230	ND	4.080	ND	4.230	4.5	4.380	ND	4.230	ND	4.080	ND
Cyclohexane	4.280	4.91	4.130	9.71	4.280	ND	4.440	4.52	4.280	ND	4.130	ND
1,2-Dichlorobenzene	3.950	ND	3.810	ND	3.950	ND	4.090	ND	3.950	ND	3.810	ND
1,4-Dichlorobenzene	4.000	ND	3.860	ND	4.000	ND	4.150	ND	4.000	ND	3.860	ND
cis-1,2-Dichloroethene	3.440	41.2	3.320	82.3	3.440	35.5	3.570	61.1	3.440	31.8	3.320	29.1
trans-1,2-Dichloroethene	4.120	ND	3.970	ND	4.120	ND	4.260	ND	4.120	ND	3.970	ND
Ethanol	4.820	ND	4.640	ND	4.820	ND	4.990	ND	4.820	ND	5.720	ND
Ethyl Acetate	6.100	ND	5.890	ND	6.100	ND	6.320	ND	6.100	ND	5.890	ND
Ethylbenzene	3.780	92.7	3.640	13.2	3.700	58	3.920	ND	3.780	61.2	3.640	22.2
4-Ethyltoluene	3.360	23.2	3.240	ND	3.360	30.3	3.480	ND	3.360	23.6	3.240	ND
Freon 11	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
n-Heptane	3.440	106	3.320	86	3.440	63.9	3.570	46.6	3.440	57.8	3.320	10.9
Hexane	4.060	57.2	3.920	130	4.060	27	4.200	47.6	4.060	31.1	3.920	13.4
Isopropyl Alcohol	3.300	ND	3.190	ND	3.300	ND	3.420	ND	3.300	ND	3.190	ND
Methylene Chloride	5.850	ND	5.640	ND	5.850	11.6	6.060	16.3	5.850	9.32	5.640	8.19
Methyl Isobutyl Ketone (MIBK)	3.300	ND	3.190	ND	3.300	4.51	3.420	ND	3.300	4.38	3.190	ND
2-Propanol (IPA)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Propene	50.200	3730	48.800	4100	50.900	2410	51.500	2370	49.900	2820	48.400	2370
Propylene	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Styrene	2.320	9.27	2.240	ND	2.320	8.06	2.410	ND	2.320	6.83	2.240	ND
Tetrachloroethene (PCE)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Tetrachloroethylene	3.750	ND	3.620	ND	3.750	ND	3.890	ND	3.750	ND	3.620	ND
Toluene	26.500	2690	25.700	2860	26.900	1090	2.760	9.72	26.300	1900	25.600	377
1,2,4-Trichlorobenzene	2.910	ND	2.810	ND	2.910	ND	3.020	ND	2.910	ND	2.810	ND
Trichloroethene (TCE)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Trichloroethylene	3.950	8.06	3.810	26.5	3.950	21.4	4.090	9.21	3.950	9.34	3.910	5.18
Trichlorofluoromethane(F-11)	7.980	ND	7.700	ND	7.980	ND	8.260	ND	7.980	ND	7.700	ND
1,2,4-Trimethylbenzene	3.700	104	3.560	ND	3.700	99	3.830	ND	3.700	101	3.560	ND
1,3,5-Trimethylbenzene	4.590	38.3	3.240	ND	4.590	33.2	4.760	ND	4.590	33.2	4.430	ND
2,2,4-Trimethylpentane	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Vinyl Chloride	5.820	ND	5.620	ND	5.820	ND	6.030	ND	5.820	ND	5.620	ND
m & p-Xylene	4.730	159	4.560	ND	4.730	111	4.900	6.41	4.730	102	4.560	31.1
o-Xylene	4.540	57.8	4.370	ND	4.540	38	5.890	ND	4.540	34.1	4.370	ND
Total VOCs	**N/A**	**7,139**	**N/A**	**7,352**	**N/A**	**4,078**	**N/A**	**2592**	**N/A**	**5,246**	**N/A**	**2867**

July 2011

APPENDIX B-5:

Speciated Siloxane and Hydrogen Sulfide Sampling Summary

Date of Sampling	Approximate Volume of Gas Treated (Million Cubic Feet)	Total Siloxane (ppmv)		H2S			
				OCSD AQMD 307-91 (ppmv)		OCSD Draeger Tube (ppmv)	
		Inlet	Outlet	Inlet	Outlet	Inlet	Outlet
3/16/2010	0.00	3.58	<MDL	N/A	N/A	N/A	N/A
4/7/2010	27.26	8.51	<MDL	N/A	N/A	N/A	N/A
4/21/2010	53.41	N/A	N/A	25.70	ND	26	ND
4/29/2010	68.93	15.70	ND	N/A	N/A	N/A	N/A
5/11/2010	91.86	N/A	N/A	31.70	0.263	31	ND
5/27/2010	122.58	2.67	0.015	N/A	N/A	N/A	N/A
6/8/2010	144.70	N/A	N/A	27.97	2.162	30	2
6/11/2010	146.46	8.49	0.248	N/A	N/A	N/A	N/A
6/12/2010	Carbon media changed.						
6/22/2010	18.44	N/A	N/A	21.62	ND	27	-
6/29/2010	32.70	8.69	N/A	N/A	N/A	N/A	N/A
7/7/2010	46.34	N/A	N/A	28.57	ND	25	N/A
7/21/2010	68.89	N/A	N/A	24.87	ND	25	N/A
8/3/2010	90.04	N/A	N/A	27.45	ND	25	N/A
8/12/2010	106.00	N/A	N/A	28.19	ND	26	N/A
8/12/2010	106.00	3.73	ND	N/A	N/A	N/A	N/A
9/1/2010	137.15	4.57	<MDL	N/A	N/A	N/A	N/A
9/1/2010	137.15	N/A	N/A	14.69	ND	14	N/A
9/14/2010	162.45	N/A	N/A	23.01	0.545	23	N/A
9/15/2010	164.63	4.35	<MDL	N/A	N/A	N/A	N/A
9/17/2010	168.63	N/A	N/A	N/A	N/A	-	2.5
9/20/2010	173.62	5.73	<MDL	N/A	N/A	N/A	N/A
9/21/2010	Carbon media changed.						
11/4/2010	43.40	5.23	N/A	N/A	N/A	N/A	N/A
1/12/2011	114.53	6.55	N/A	N/A	N/A	N/A	N/A
1/25/2011	137.78	N/A	N/A	28.54	ND	27	N/A
2/9/2011	156.47	N/A	N/A	31.87	1.755	30	N/A
2/9/2011	156.47	4.58	<MDL	N/A	N/A	N/A	N/A
2/14/2011	Carbon media changed.						
2/23/2011	17.72	N/A	N/A	24.46	ND	25	N/A
2/24/2011	20.09	6.64	N/A	N/A	N/A	N/A	N/A

Notes:
(1) All samples are taken using Tedlar Bags, except where otherwise noted as using Draeger® tubes f
(2) Inlet and outlet sample results from 5/19/10 are not accurate due to an error in collection, indicated by high nitrogen composition (>5%), and are not included in the minimum, maximum
(3) Outlet sample results from 6/29/10 are not accurate due to an error in collection, indicated by high nitrogen composition (>5%), and are not included in the minimum, maximum and average.
(4) Inlet and outlet sample results from AccuLabs on 8/12/10 are not accurate due to an error in collection, indicated by high nitrogen composition (>5%), and are not included in the minimum,
(5) Sample results from 8/19/10 are not consistent with sample results from other laboratories and are concluded to be erroneous and not included in the minimum, maximum and average.
(6) N/A indicates that the compound was not analyzed for.
(7) ND indicates non-detect.
(8) <MDL indicates that the result, if any, was less than the method detection limit.

APPENDIX C-1:

CO and NOx with Portable Analyzer Summary

CO and NOx with Portable Analyzer Summary
Plant 1 - Catalytic Oxidizer and Selective Catalytic Reduction

Date	Load (%)	DG (%)	Testing Time (min)	NH3 Draeger Tube (ppm)	Before Cat Ox		After Cat Ox		After SCR		CO Reduction	NOx Reduction
					CO (ppm) Adj to 15% O2	NOx (ppm) Adj to 15% O2	CO (ppm) Adj to 15% O2	NOx (ppm) Adj to 15% O2	CO (ppm) Adj to 15% O2	NOx (ppm) Adj to 15% O2		
3/29/2010	80	88	15	N/A	448.4	38.7	5.8	39.8	5.3	1.3	98.8%	96.6%
3/30/2010	82	95	15	N/A	453.0	33.5	0.1	34.2	3.3	4.9	99.3%	85.2%
3/31/2010	60	95	10	N/A	353.9	29.7	N/A	N/A	4.0	1.4	98.9%	95.4%
3/31/2010	80	95	10	N/A	431.2	33.9	N/A	N/A	9.2	4.5	97.9%	86.8%
3/31/2010	100	95	10	N/A	452.3	36.5	N/A	N/A	0.0	6.7	100.0%	81.6%
3/31/2010	110	95	10	N/A	446.2	41.9	N/A	N/A	0.3	5.8	99.9%	86.1%
3/31/2010	60	50	10	N/A	347.3	39.6	N/A	N/A	13.8	7.3	96.0%	81.6%
3/31/2010	80	50	10	N/A	472.0	39.9	N/A	N/A	11.5	6.0	97.6%	85.0%
3/31/2010	100	50	10	N/A	513.5	43.7	N/A	N/A	15.7	6.8	97.0%	84.5%
3/31/2010	110	50	10	N/A	478.7	45.8	N/A	N/A	3.4	9.3	99.3%	79.7%
4/1/2010	60	0	10	N/A	380.9	43.6	N/A	N/A	0.6	0.9	99.8%	97.9%
4/1/2010	80	0	10	N/A	559.9	44.1	N/A	N/A	1.3	1.3	99.8%	97.1%
4/1/2010	100	0	10	N/A	591.8	48.1	N/A	N/A	6.0	10.2	99.0%	78.7%
4/1/2010	110	0	10	N/A	532.9	51.9	N/A	N/A	1.3	11.4	99.8%	77.9%
4/7/2010	110	95	15	<MDL	367.5	46.2	1.7	47.3	1.6	10.1	99.6%	78.2%
4/14/2010	100	95	15	N/A	435.5	37.4	0.9	37.8	4.0	5.7	99.1%	84.8%
4/21/2010	90	95	15	<MDL	369.3	41.4	0	41.9	1.5	6.7	99.6%	83.8%
4/29/2010	94	95	15	<MDL	369.3	40.3	2.3	40.1	5.1	8.5	98.6%	78.8%
5/6/2010	100	95	15	<MDL	440.8	41.3	0.7	39.6	2.2	2.7	99.5%	93.5%
5/19/2010	100	95	15	<MDL	525.1	34.5	3.0	36.5	4.7	1.2	99.1%	96.5%
6/29/2010	100	97	15	<MDL	439.7	42.4	2.4	40.5	17.0	8.1	96.1%	81.0%
7/28/2010	95	97	15	<MDL	458.8	39.8	0.1	37.8	8.8	7.3	98.1%	81.7%
8/12/2010	100	96	15	<MDL	408.4	43.5	4.9	44.0	7.6	10.1	98.1%	76.7%
11/4/2010	100	96	15	<MDL	598.7	43.2	0.0	42.5	0.0	10.2	100.0%	76.3%
1/12/2011	100	96	15	<MDL	509.4	37.9	15.1	36.4	17.2	7.7	96.6%	79.7%
2/24/2011	100	95	15	<MDL	496.8	38.5	0.0	39.1	0.1	6.9	100.0%	82.1%

Notes:
(1) N/A indicates that this data was not collected.
(2) <MDL indicates that the result, if any, was less than the detection limit.

APPENDIX C-2:

Technical Memorandum:
OCSD Catalytic Oxidizer/SCR Pilot Study: VOC Evaluation

Technical Memorandum

Date: July 13, 2011

To: File

From: Kit Liang, Malcolm Pirnie, WHI; Daniel Stepner, Malcolm Pirnie, WHI

Re: OCSD Cat Ox/SCR Pilot Study: VOC Evaluation

Project No.: 0788-187

Project Background

The internal combustion (IC) engines at Orange County Sanitation District (OCSD) are subject to South Coast Air Quality Management District (SCAQMD) Rule 1110.2. Rule 1110.2 provides emission limits and monitoring requirements for all stationary and portable engines over 50 brake-horsepower (bhp). Rule 1110.2 (Emissions from Gaseous- and Liquid- Fueled Engines) was promulgated to reduce the NOx, CO and volatile organic compounds (VOC) emissions from engines over 50 bhp. On February 1, 2008, Rule 1110.2 was amended in order to achieve further emissions reductions from stationary engines based on the cleanest available technologies. Under the February 2008 amendments to Rule 1110.2 shown below, more stringent NOx, CO, and VOC limits were adopted, to become effective for biogas-fueled engines in July 2012 provided a technology assessment confirms that the limits below are achievable.

■ NOx limit was lowered from 36 ppm (or ~ 45 ppm*) to 11 ppm at 15% O_2.

■ VOC limit was lowered from 250 ppm* to 30 ppm at 15% O_2.

■ CO limit was lowered from 2,000 ppm to 250 ppm at 15% O_2.

* Existing limits allow for an alternative emission limit for OCSD engines based on the engine efficiency correction factor.

A pilot study of a Johnson Matthey catalytic oxidizer/Selective Catalytic Reduction (Cat Ox/SCR) system was performed at OCSD Plant 1 on Engine 1 from April 2010 through March 2011. Design of the pilot system included an SCR system for NOx emission reduction, an oxidation catalyst unit for CO and VOC reduction (including formaldehyde), and a DGCS upstream from the IC engines for removal of siloxanes to prevent fouling of the catalysts. Additional benefits of the DGCS include the removal of total reduced sulfur and total volatile organic compounds. The DGCS cleaned the digester gas fuel for all three Plant 1 IC engines. However, the Cat Ox/SCR system was only installed on Engine 1. As part of this pilot testing program, a sampling program was initiated to determine the concentrations of VOCs at the inlet and outlet of the Cat Ox/SCR system. The sampling was performed by SCEC, a firm listed in the SCAQMD Laboratory Approval Program (LAP). The VOC sampling was performed using SCAQMD Method 25.3.

This memorandum describes the sampling method for VOCs used during the testing and the VOCs concentration results. In addition, the memorandum compares the result found for Engine 1 with results from a recent regulatory compliance study performed on Engines 1, 2, and 3 at Plant 1.

VOC Sampling SCAQMD Method 25.3

The SCAQMD compliance methods for testing for VOCs are SCAQMD Methods 25.1 and 25.3. In general, SCAQMD Method 25.1 is used to collect samples where VOC concentrations are greater or equal to 50 ppm as carbon (ppmC). SCAQMD Method 25.3 is used where VOC concentrations are less than 50 ppmC. With both methods, exhaust gas samples are drawn into evacuated canisters through condensate traps. In Method 25.3, the condensate, largely consisting of water, is collected in the traps at ice water temperature (~32°F), preventing unrecoverable VOC from being collected in the canisters. Based on previous sampling, VOC concentrations in the exhaust gas are expected to be below 50 ppm; therefore, SCAQMD Method 25.3 was used for this pilot study. During the pilot study, exhaust samples are taken at the engine exhaust, prior to the catalyst oxidizer, and at the stack exhaust, following the SCR and heat recovery boiler. Analysis was performed at the laboratory.

The VOC concentration as non-methane non-ethane organic compounds (NMNEOC) is determined by combining the independent analysis results of the condensate in each trap and the gas in the associated canister. The condensate is analyzed for total organic carbon by liquid injection into an infra-red organic carbon analyzer. The gaseous sample in the canister is analyzed for NMNEOC using a combination of gas chromatography, oxidizer, methanizer, and flame ionization detector. Carbon monoxide and fixed gases in the sample can be determined by analysis of the canister portion of the sample.

VOC Monitoring Results and Discussion

Pilot testing of the Cat Ox/SCR system commenced on April 1, 2010 and continued through March 31, 2011. Throughout the pilot testing, SCEC tested VOCs at the engine exhaust before the catalytic oxidizer and at the stack outlet after the SCR and heat recovery boiler on the roof of the Central Generator (CenGen) Building. Results of the VOC data are summarized in Table 1.

Table 1 presents a summary of the VOC field measurements using SCAQMD Method 25.3. The percent reduction of VOC ranged from 59.1% to 97.8%. The average concentration of VOC at the stack exhaust was 3.58 ppmv, below the emission limit of 30 ppmv in the Amended Rule 1110.2.

Table 1:
Measured VOC Concentrations – Plant 1 Engine 1

Date	Engine Exhaust (ppmv)	Stack Exhaust (ppmv)	% Reduction
4/7/2010	27.1	2.0	90.4
5/11/2010	33.0	0.7	97.8
8/12/2010	15.1	5.4	64.0
11/4/2010	10.3	4.2	59.1
2/24/2011	25.0	5.0	80.2
Average	**21.8**	**3.6**	**83.6**

Notes: 1.   All concentrations are adjusted to 15% O_2.
         2.   All samples were collected using SCAQMD Method 25.3

Data measured during the pilot testing period was compared to VOC concentrations measured by SCEC for the *OCSD Plant No. 1 Unit Nos. 1, 2, 3 Rule 1110.2 8760 Hour & Permit Compliance Test Report for Year 2011*. Table 2 summarizes the annual permit compliance VOC test results for OCSD Plant No. 1. The Unit No. 1 (Engine 1) VOC stack exhaust concentration measured during the annual Rule 1110.2 compliance testing was 3.24 ppmv. This is in the same range of the VOC concentrations measured during the pilot testing period, confirming the effectiveness of the catalytic oxidizer in removing VOC from the engine exhaust.

Table 2:
Annual Rule 1110.2 Compliance Test VOC Concentrations - Plant No. 1

Date	Unit No. (Engine)	Sampling Method	Stack Exhaust (ppmv)
1/13/2011	1	SCAQMD Method 25.3	3.24
1/12/2011	2	SCAQMD Method 25.1	97.2
1/11/2011	3	SCAQMD Method 25.1	96.9

Note: 1.   All concentrations are adjusted to 15% O_2.

As discussed earlier, the DGCS was installed on the digester gas header and provides cleaned digester gas fuel to all three IC engines. The Cat Ox/SCR post-combustion control was installed on Engine 1, but not on Unit Nos. 2 and 3 (Engines 2 and 3). As shown in Table 2, the VOC stack exhaust concentrations for Engines 2 and 3 were 97.2 and 96.9 ppmv, respectively. This was much higher than the VOC concentrations measured at the Engine 1 exhaust before the Cat Ox/SCR system during the pilot testing period, which averaged 21.84 ppmv VOCs. One possible explanation to this is the arrangement of the sampling port at Engine No. 1 before the catalytic oxidizer. Due to restrictions on placement of the Method 25.3 probe at the Engine No. 1 exhaust before the Cat Ox/SCR system, accuracy in taking this sample is reduced. Typically using sampling Method SCAQMD 25.3, two samples are gathered from two separate probes and the results of the analyses are averaged. SCAQMD mandates that when the results from the two samples differ by more than 20%, that the higher value of the two samples be reported. In the experience of the SCEC lab, this occurs approximately half of the time. Otherwise, the values are averaged.

In this instance, the valve at the engine exhaust sampling port was not large enough to co-locate two probes next to each other and it was not possible to expand the sampling port. Therefore, the sample and duplicate sample were not taken at the same time, but one after the other. The data presented in Table 2 above for the engine exhaust represents the higher of the two sample data results, in line with AQMD's general mandate. Despite the lower accuracy in the engine exhaust sample, the sample taken at the stack exhaust met the SCAQMD accuracy criteria. Moving forward, it is recommended to install a larger sampling port to allow for greater accuracy through the co-location of the Method 25.3 probes.

Conclusions and Recommendations

Upon review of the data from the five sampling events, it was determined that the catalytic oxidizer (with a DGCS) is successful in reducing the VOC concentration to below the emission limit of 30 ppmv in Amended Rule 1110.2. The catalytic oxidizer system met the vendor guarantee of 25 ppmvd VOCs. During the pilot testing period, the average VOC inlet concentration at the engine exhaust was 21.8 ppmv, and the average VOC outlet concentration at the stack exhaust was 3.6 ppmv. The VOC outlet concentration was confirmed during the OCSD Plant No. 1 annual permit compliance testing in January 2011 (see Table 2).

During the annual permit compliance testing in January 2011, it was also found that the VOC concentration at the Engine Nos. 2 and 3 Stack Exhaust were 97.2 ppmv and 96.9 ppmv, respectively. This is much higher than that measured at the Engine No. 1 exhaust before the catalytic oxidizer. This may have occurred due to restrictions with the Engine No. 1 exhaust sample port. In the future, it is recommended to install a larger sampling port at the engine exhaust.

References

1   CARB, 1991. "Method 430 – Determination of Formaldehyde and Acetaldehyde in Emissions from Stationary Sources." December 1991.

2   EPA, 2003. "Appendix A to Part 63 – Test Methods. Method 323 – Measurement of Formaldehyde Emissions from Natural Gas-Fired Stationary Sources – Acetyl Acetone Derivitization Method." Federal Register, Vol. 68, No. 9, January 14, 2003.

3   SCAQMD, 2000. "Method 25.3 – Determination of Low Concentration Non-Methane Non-Ethane Organic Compound Emissions from Clean Fueled Combustion Sources." March 2000.

APPENDIX C-3:

CEMS Emissions Summary

Validated Daily 15-Minute Block Average
Daily Average and Maximum Emissions Summary Data from CEMS
Plant 1 - Catalytic Oxidizer and Selective Catalytic Reduction

Date	Avg. Engine Exhaust NOx @15% O2 (ppmvd)	Average Stack Exhaust NOx @15% O2 (ppmvd)	Average Stack Exhaust CO @15%O2 (ppmvd)	Maximum Ammonia Slip	Maximum Engine Exhaust NOx @15% O2 (ppmvd)	Maximum Stack Exhaust NOx @15% O2 (ppmvd)	Maximum Stack Exhaust CO @15%O2 (ppmvd)	Average Engine Load (%)	Max Engine Load (%)	Average Fuel Ratio (% DG)	Notes
4/1/2010	33.49	-	6.20	-	44.32	-	8.97	96.13	113.65	0%	Note 1.
4/2/2010	31.28	-	5.70	-	34.35	-	6.28	96.84	100.74	96%	Note 1.
4/3/2010	30.16	-	5.75	-	31.61	-	6.24	97.55	101.02	91%	Note 1.
4/4/2010	30.05	-	5.82	-	32.05	-	6.33	96.80	103.18	83%	Note 1.
4/5/2010	33.96	-	5.84	-	36.08	-	6.31	95.15	101.43	90%	Note 1.
4/6/2010	34.03	-	5.78	-	37.00	-	6.73	94.82	100.79	74%	Note 1.
4/7/2010	35.47	-	5.58	-	38.97	-	6.08	96.88	105.06	96%	Note 1.
4/8/2010	32.89	-	5.93	-	37.44	-	7.87	91.57	101.69	94%	Note 1.
4/9/2010	31.93	-	5.78	-	33.69	-	6.28	97.27	100.60	96%	Note 1.
4/10/2010	31.49	-	5.93	-	33.18	-	6.34	96.90	100.78	92%	Note 1.
4/11/2010	30.94	-	6.04	-	33.04	-	6.55	94.72	99.67	91%	Note 1.
4/12/2010	31.69	-	6.05	-	34.34	-	6.71	88.29	96.25	88%	Note 1.
4/13/2010	33.11	-	5.95	-	37.06	-	6.53	88.30	98.81	90%	Note 1.
4/14/2010	31.98	-	5.87	-	35.12	-	6.31	95.47	100.75	89%	Note 1.
4/15/2010	31.09	-	5.98	-	34.46	-	6.37	97.02	100.38	90%	Note 1.
4/16/2010	31.36	-	5.95	-	33.19	-	6.26	96.80	100.46	92%	Note 1.
4/17/2010	30.94	-	5.92	-	32.69	-	6.25	97.66	104.81	93%	Note 1.
4/18/2010	30.70	-	5.95	-	34.11	-	6.47	95.54	100.86	95%	Note 1.
4/19/2010	30.28	-	6.09	-	33.10	-	6.81	90.86	99.29	88%	Note 1.
4/20/2010	29.62	-	6.10	-	33.35	-	6.44	83.53	93.10	90%	Note 1.
4/21/2010	33.03	-	5.61	-	34.76	-	5.88	95.39	100.22	93%	Note 1.
4/22/2010	33.03	-	5.62	-	35.49	-	5.91	97.64	100.88	96%	Note 1.
4/23/2010	33.73	-	5.87	-	35.89	-	7.05	96.10	100.84	96%	Note 1.
4/24/2010	33.49	-	5.98	-	35.68	-	6.15	97.92	102.18	96%	Note 1.
4/25/2010	30.79	-	6.18	-	32.34	-	6.54	96.58	100.34	91%	Note 1.
4/26/2010	30.40	-	6.22	-	32.20	-	6.75	92.60	99.67	86%	Note 1.
4/27/2010	31.10	-	6.13	-	32.92	-	6.83	95.33	101.54	86%	Note 1.
4/28/2010	32.11	-	6.19	-	36.67	-	7.37	93.53	102.53	53%	Note 1.
4/29/2010	35.53	-	5.67	-	38.83	-	6.40	98.71	107.61	96%	Note 1.
4/30/2010	34.85	-	5.58	-	37.68	-	5.79	103.15	106.09	96%	Note 1.
5/1/2010	32.93	-	5.78	-	34.68	-	6.00	102.47	106.53	96%	Note 1.
5/2/2010	34.26	-	5.81	-	36.48	-	6.25	102.95	106.06	92%	Note 1.
5/3/2010	34.39	-	6.18	-	42.06	-	9.72	96.31	105.57	53%	Note 1.
5/4/2010	32.80	-	5.97	-	34.46	-	6.53	92.11	100.49	0%	Note 1.
5/5/2010	26.49	-	4.80	-	27.54	-	5.18	83.99	92.92	0%	Note 1.
5/6/2010	32.64	-	5.19	-	35.45	-	5.81	102.76	106.54	0%	Note 1.
5/7/2010	32.33	-	5.52	-	34.26	-	5.96	103.38	107.95	96%	Note 1.
5/8/2010	32.14	-	5.66	-	34.01	-	6.13	103.18	106.94	85%	Note 1.
5/9/2010	31.33	-	5.82	-	36.50	-	6.30	96.36	105.53	89%	Note 1.
5/10/2010	31.77	-	5.76	-	36.68	-	7.46	85.73	98.86	86%	Note 1.
5/11/2010	33.55	-	5.59	-	38.04	-	6.35	97.79	106.06	89%	Note 1.
5/12/2010	32.02	-	5.73	-	37.30	-	6.66	102.01	106.44	55%	Note 1.
5/13/2010	31.47	-	5.93	-	33.54	-	6.54	97.90	106.97	0%	Note 1.
5/14/2010	33.74	-	5.68	-	35.92	-	5.94	102.47	107.02	87%	Note 1.
5/15/2010	34.32	-	5.74	-	36.26	-	5.92	102.79	106.02	87%	Note 1.
5/16/2010	32.94	-	5.77	-	35.24	-	6.25	103.30	106.55	87%	Note 1.
5/17/2010	32.28	-	5.75	-	34.83	-	6.31	100.58	105.76	94%	Note 1.
5/18/2010	30.24	-	5.90	-	34.62	-	6.57	100.79	106.94	96%	Note 1.
5/19/2010	30.15	-	5.85	-	31.65	-	6.68	101.48	107.08	86%	Note 1.
5/20/2010	31.29	-	5.88	-	34.10	-	6.42	103.01	107.64	90%	Note 1.
5/21/2010	30.16	-	6.12	-	33.08	-	6.66	102.86	107.93	96%	Note 1.
5/22/2010	32.54	-	5.84	-	35.08	-	6.09	103.12	106.52	90%	Note 1.
5/23/2010	34.07	-	5.90	-	36.53	-	6.40	102.80	107.51	93%	Note 1.
5/24/2010	32.96	-	5.99	-	36.36	-	6.39	102.46	109.29	90%	Note 1.
5/25/2010	30.21	-	5.98	-	33.13	-	6.43	98.64	107.62	91%	Note 1.

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Date	Avg. Engine Exhaust NOx @15% O2 (ppmvd)	Average Stack Exhaust NOx @15% O2 (ppmvd)	CO @15%O2 (ppmvd)	Maximum Ammonia Slip	Maximum Engine Exhaust NOx @15% O2 (ppmvd)	Maximum Stack Exhaust NOx @15% O2 (ppmvd)	CO @15%O2 (ppmvd)	Average Engine Load (%)	Max Engine Load (%)	Average Fuel Ratio (% DG)	Notes
5/26/2010	31.18	-	6.06	-	33.84	-	6.44	101.02	107.79	90%	Note 1.
5/27/2010	32.54	-	6.62	-	42.79	-	7.39	107.57	116.77	0%	Note 1.
5/28/2010	32.54	-	7.13	-	36.76	-	7.87	108.29	112.89	90%	Note 1.
5/29/2010	33.32	-	7.21	-	38.06	-	8.14	108.48	113.00	90%	Note 1.
5/30/2010	32.29	-	7.14	-	37.57	-	7.81	105.35	111.41	95%	Note 1.
5/31/2010	32.38	-	7.09	-	34.35	-	7.85	102.68	110.76	93%	Note 1.
6/1/2010	32.12	-	7.08	-	34.42	-	7.70	99.23	106.01	91%	Note 1.
6/2/2010	32.10	-	7.12	-	35.69	-	7.82	99.22	109.84	92%	Note 1.
6/3/2010	32.60	-	7.21	-	35.06	-	7.62	102.76	106.04	90%	Note 1.
6/4/2010	31.77	-	7.65	-	34.64	-	8.26	102.72	107.91	90%	Note 1.
6/5/2010	30.68	-	8.03	-	33.03	-	8.47	102.76	106.89	0%	Note 1.
6/6/2010	31.73	-	8.66	-	33.23	-	9.22	103.14	106.57	90%	Note 1.
6/7/2010	29.42	-	8.50	-	34.22	-	10.27	92.20	107.57	87%	Note 1.
6/8/2010	28.04	3.67	8.82	5.25	30.71	6.70	10.15	89.57	106.09	93%	Urea injection set points modified to reduce ammonia slip.
6/9/2010	29.08	5.14	11.05	1.75	30.72	6.98	12.65	100.68	108.52	90%	
6/10/2010	29.03	4.96	14.33	1.38	32.07	6.50	17.45	103.62	107.96	90%	
6/11/2010	35.28	8.58	14.73	3.66	39.35	10.49	17.69	88.07	107.98	0%	
6/12/2010	35.15	8.40	13.39	2.46	41.26	13.87	16.32	87.35	104.66	0%	Engine operated on Natural Gas from 17:26 to 17:31.
6/13/2010	28.12	4.80	10.94	1.31	30.63	6.24	12.90	92.08	101.85	96%	
6/14/2010	27.52	4.87	9.13	1.21	29.15	6.22	9.61	85.14	94.49	54%	The CEMS failed calibration repeatedly (both NOx and CO low range were out of control). Adjustments were made to bring it back into calibration (Note 2).
6/15/2010	28.04	4.60	9.54	1.12	32.15	6.77	11.00	91.91	99.76	87%	
6/16/2010	30.75	5.59	9.59	1.13	35.26	7.78	10.36	97.30	107.73	81%	
6/17/2010	30.87	5.62	9.92	1.15	34.07	7.32	10.61	103.26	105.74	96%	
6/18/2010	29.87	4.94	9.90	0.97	31.55	6.03	10.60	101.24	105.90	96%	
6/19/2010	31.23	6.02	9.03	1.34	33.29	7.23	9.56	97.62	101.06	96%	
6/20/2010	32.09	6.44	8.69	1.74	34.59	7.71	9.19	97.83	102.80	96%	
6/21/2010	34.17	7.36	8.40	1.69	36.50	9.06	9.07	99.29	103.92	91%	
6/22/2010	33.88	7.24	8.42	2.15	37.69	8.89	9.11	98.75	106.15	90%	
6/23/2010	33.03	6.83	8.28	2.11	36.24	8.99	9.10	97.58	104.97	94%	
6/24/2010	32.86	6.89	8.65	2.40	36.61	9.15	9.41	102.87	106.83	96%	Urea injection shut off for urea delivery and level sensor calibration from 8:08 to 9:22 (Note 3).
6/25/2010	32.53	6.83	8.91	2.09	34.24	7.73	9.31	103.43	106.78	92%	
6/26/2010	33.67	7.61	8.40	3.11	38.08	8.94	8.93	103.06	105.96	94%	
6/27/2010	33.46	7.88	8.21	4.39	38.36	8.96	8.89	103.32	106.45	98%	CEMS inlet sample flow alarm occurred causing invalid data. CEMTEK technician responded and found sample pump to be in need of a rebuild. Necessary repairs were made.
6/28/2010	34.80	7.67	8.38	2.47	36.82	9.10	8.98	103.11	106.70	98%	
6/29/2010	34.16	7.61	8.46	1.98	36.75	8.95	9.29	103.41	108.30	93%	
6/30/2010	34.39	7.83	8.09	3.01	37.94	10.29	9.57	99.16	110.60	85%	
7/1/2010	34.16	7.43	7.83	2.14	35.40	8.14	7.91	93.56	95.94	92%	
7/2/2010	N/A	N/A	N/A	N/A	0.00	N/A	N/A	N/A	N/A	0%	The engine experience high NOx inlet at the engine exhaust due to a new automation issue, which in turn caused high NOx at the stack outlet (Note 4).
7/3/2010	N/A	N/A	N/A	N/A	0.00	N/A	N/A	N/A	N/A	0%	
7/4/2010	36.43	8.74	8.02	2.06	39.94	10.37	9.18	99.37	105.85	90%	
7/5/2010	35.95	8.30	8.13	2.37	39.78	10.33	9.24	100.91	105.97	89%	
7/6/2010	34.81	7.86	7.80	2.21	38.84	9.78	9.13	97.97	105.00	0%	Note 2.
7/7/2010	33.89	7.49	7.47	2.68	37.70	9.38	8.32	93.48	100.26	92%	
7/8/2010	32.69	6.79	8.18	1.86	36.29	8.77	9.23	97.97	107.36	83%	
7/9/2010	32.07	6.43	8.70	1.32	34.42	7.76	9.33	97.63	99.70	83%	
7/10/2010	32.57	6.70	8.22	1.68	35.97	8.18	9.27	97.70	101.85	83%	
7/11/2010	31.92	6.56	8.09	1.56	36.21	8.52	9.15	92.72	99.52	87%	
7/12/2010	32.69	7.23	7.72	1.86	37.08	9.47	8.95	90.23	97.66	89%	
7/13/2010	33.00	7.19	7.79	2.12	36.37	8.91	8.93	96.10	101.79	88%	
7/14/2010	33.28	7.38	7.71	2.04	38.59	10.02	8.82	93.08	99.29	91%	
7/15/2010	33.49	7.34	7.93	2.26	37.32	9.50	8.58	98.93	103.17	97%	
7/16/2010	31.95	6.75	8.23	1.67	33.71	7.98	8.88	98.17	103.58	87%	

July 2011

Validated Daily 15-Minute Block Average
Daily Average and Maximum Emissions Summary Data from CEMS
Plant 1 - Catalytic Oxidizer and Selective Catalytic Reduction

Date	Avg. Engine Exhaust NOx @15% O2 (ppmvd)	Average Stack Exhaust NOx @15% O2 (ppmvd)	CO @15%O2 (ppmvd)	Maximum Ammonia Slip	Maximum Engine Exhaust NOx @15% O2 (ppmvd)	Maximum Stack Exhaust NOx @15% O2 (ppmvd)	CO @15%O2 (ppmvd)	Average Engine Load (%)	Max Engine Load (%)	Average Fuel Ratio (% DG)	Notes
7/17/2010	33.16	7.43	7.87	2.39	37.15	9.46	9.08	93.85	105.06	89%	
7/18/2010	32.37	7.02	7.83	2.02	35.65	9.00	8.90	94.85	101.40	90%	
7/19/2010	32.74	7.22	7.91	2.46	36.69	9.50	9.16	95.15	101.60	88%	
7/20/2010	32.05	6.86	7.80	39.38	36.12	10.44	11.46	94.30	100.26	0%	The engine was brought offline at the request of the OCSD's contractor who is performing electrical upgrades (Note 2).
7/21/2010	32.46	6.85	7.99	1.88	34.65	7.73	8.99	98.29	102.81	94%	
7/22/2010	32.78	6.99	7.97	2.15	35.41	8.30	9.11	95.07	102.88	87%	
7/23/2010	30.76	5.96	8.36	1.75	33.43	7.40	9.44	95.39	99.27	87%	
7/24/2010	31.02	6.42	8.42	7.59	34.77	9.33	42.23	93.60	118.80	0%	Note 2.
7/25/2010	32.71	6.94	8.02	3.26	37.17	9.35	9.29	97.57	102.19	89%	
7/26/2010	34.25	7.62	7.55	100.43	41.43	9.23	8.48	96.06	107.34	0%	Note 2.
7/27/2010	32.69	6.99	7.57	2.16	38.25	9.15	8.49	92.14	99.98	87%	
7/28/2010	32.15	6.88	7.74	3.47	35.77	8.68	9.26	93.20	112.96	0%	Note 2.
7/29/2010	32.04	7.22	6.61	2.48	34.72	8.63	8.44	93.08	99.08	0%	Note 2.
7/30/2010	30.92	6.71	6.38	2.07	32.76	7.60	6.67	94.17	101.75	90%	
7/31/2010	30.03	6.34	6.48	2.73	31.93	7.27	7.61	92.62	100.70	90%	
8/1/2010	30.79	6.69	6.64	2.84	33.38	8.17	7.67	93.19	104.33	90%	
8/2/2010	31.93	7.34	6.42	2.42	36.03	9.55	7.36	91.59	97.50	89%	
8/3/2010	32.58	7.68	6.26	25.61	36.79	9.42	7.44	92.77	99.37	0%	Note 2.
8/4/2010	32.44	7.78	6.18	10.42	34.43	9.34	7.31	94.30	98.94	0%	Note 2.
8/5/2010	31.95	7.25	6.51	3.20	35.74	9.00	13.21	89.75	99.70	0%	Note 2. High Stack Exhaust NOx due to Natural Gas fuel.
8/6/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
8/7/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
8/8/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	Engine was offline from 8/5/10 16:09 through 8/11/10 7:48.
8/9/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
8/10/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
8/11/2010	34.39	9.27	6.08	3.49	37.74	10.98	6.88	90.62	95.53	0%	Note 2.
8/12/2010	34.01	8.74	6.41	3.19	37.25	10.07	7.49	93.14	102.71	0%	
8/13/2010	32.57	8.41	6.40	3.06	37.04	11.15	7.02	85.86	97.19	97%	
8/14/2010	33.00	8.53	6.38	3.91	37.21	10.60	7.03	86.13	92.47	96%	
8/15/2010	31.66	7.74	6.73	3.24	35.65	9.73	7.53	86.67	94.22	84%	
8/16/2010	32.48	8.43	6.52	3.42	37.09	11.79	7.34	82.17	86.64	0%	Note 2.
8/17/2010	32.96	8.93	6.48	3.45	37.66	11.46	7.01	84.22	91.31	0%	Note 2.
8/18/2010	34.78	9.68	6.46	4.98	40.13	12.49	6.99	90.49	97.30	0%	High Stack Exhaust NOx due to Natural Gas fuel.
8/19/2010	33.37	8.98	6.70	3.88	37.98	12.01	7.22	90.84	105.13	0%	High Stack Exhaust NOx due to Natural Gas fuel.
8/20/2010	33.29	8.98	6.55	5.40	38.36	11.54	7.31	91.00	95.18	90%	High Stack Exhaust NOx due to Natural Gas fuel.
8/21/2010	33.27	8.80	6.63	5.09	37.79	10.62	7.58	92.52	96.82	88%	
8/22/2010	32.57	8.36	6.71	4.44	37.77	11.61	7.57	90.78	98.04	87%	
8/23/2010	32.37	8.33	6.80	5.17	38.56	12.47	7.69	86.52	107.28	87%	
8/24/2010	29.99	7.10	6.83	3.93	37.32	12.07	7.72	80.59	105.53	0%	High Stack Exhaust NOx due to Natural Gas fuel.
8/25/2010	30.34	7.17	6.62	4.24	37.22	11.50	7.48	85.12	107.70	0%	High Stack Exhaust NOx due to Natural Gas fuel.
8/26/2010	29.45	6.37	6.92	3.98	34.92	9.43	7.51	87.33	105.39	86%	
8/27/2010	29.78	6.58	6.82	3.11	35.83	9.86	7.57	86.61	103.34	84%	
8/28/2010	30.79	7.18	6.75	3.30	36.03	10.15	7.15	86.40	100.08	90%	
8/29/2010	30.77	7.03	6.85	4.73	36.72	10.26	7.82	85.69	100.49	84%	
8/30/2010	29.61	6.07	7.11	1.88	35.04	9.48	8.06	79.22	99.68	0%	Note 2.
8/31/2010	29.05	5.76	7.07	5.45	35.34	9.77	7.77	78.41	97.15	0%	Note 2.
9/1/2010	33.39	8.60	6.69	4.19	40.53	14.28	7.51	87.49	106.41	84%	
9/2/2010	32.65	8.22	6.77	6.03	39.58	13.23	7.54	84.66	99.47	84%	
9/3/2010	32.90	8.40	6.63	8.72	39.26	12.82	7.07	89.29	109.77	91%	
9/4/2010	33.26	8.65	6.61	5.38	38.50	11.94	7.43	90.48	107.93	86%	
9/5/2010	30.00	6.86	7.14	2.32	35.04	9.24	7.90	83.59	99.00	72%	
9/6/2010	29.93	6.56	7.48	1.93	32.05	7.69	7.98	80.49	90.32	69%	
9/7/2010	31.27	7.36	7.27	2.65	33.15	8.54	7.75	79.44	83.96	71%	
9/8/2010	35.14	9.79	6.52	5.14	42.28	15.88	7.21	87.84	107.84	90%	

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Validated Daily 15-Minute Block Average
Daily Average and Maximum Emissions Summary Data from CEMS
Plant 1 - Catalytic Oxidizer and Selective Catalytic Reduction

Date	Avg. Engine Exhaust NOx @15% O2 (ppmvd)	Average Stack Exhaust NOx @15% O2 (ppmvd)	Average Stack Exhaust CO @15%O2 (ppmvd)	Maximum Ammonia Slip	Maximum Engine Exhaust NOx @15% O2 (ppmvd)	Maximum Stack Exhaust NOx @15% O2 (ppmvd)	Maximum Stack Exhaust CO @15%O2 (ppmvd)	Average Engine Load (%)	Max Engine Load (%)	Average Fuel Ratio (% DG)	Notes
9/9/2010	32.88	9.10	6.51	11.65	41.40	13.94	7.21	91.86	107.79	91%	
9/10/2010	31.34	8.32	6.78	6.44	37.96	12.85	7.26	91.29	108.76	90%	
9/11/2010	29.43	7.26	6.89	4.87	33.60	9.66	7.51	86.16	105.12	86%	
9/12/2010	28.30	6.60	7.12	3.58	32.01	8.68	7.70	84.15	100.06	84%	
9/13/2010	28.95	6.89	7.27	3.96	33.22	9.30	7.90	82.00	97.27	78%	
9/14/2010	29.73	7.52	7.10	4.40	38.04	13.94	9.50	84.29	99.48	22%	
9/15/2010	31.12	8.14	6.94	5.71	35.50	11.23	7.39	96.23	108.48	92%	
9/16/2010	31.08	8.35	6.84	7.25	39.84	15.22	7.35	93.14	108.14	82%	
9/17/2010	31.23	8.67	6.76	6.46	36.62	11.98	9.99	91.46	110.09	0%	
9/18/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	Engine was offline from 9/17/10 17:04 through 9/20/10 8:32.
9/19/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
9/20/2010	31.34	7.02	7.65	2.28	32.94	7.66	9.02	71.18	73.79	0%	Note 2.
9/21/2010	26.63	5.42	6.19	2.28	27.52	6.25	7.07	75.34	78.16	0%	Note 2.
9/22/2010	31.30	8.83	6.33	6.79	36.26	13.07	6.92	93.35	108.12	95%	
9/23/2010	31.26	8.62	6.52	6.13	36.23	12.79	7.10	96.28	108.32	98%	
9/24/2010	28.18	6.71	6.84	4.96	33.98	10.56	7.30	93.68	108.80	90%	
9/25/2010	27.04	6.35	6.68	3.71	29.74	8.06	7.15	83.96	103.31	92%	
9/26/2010	27.99	6.91	6.57	6.63	31.71	9.43	7.21	80.01	92.42	94%	
9/27/2010	28.73	7.14	6.69	4.94	34.90	12.61	7.70	81.03	97.24	85%	
9/28/2010	27.94	6.54	6.96	7.53	34.81	11.63	7.62	75.23	86.85	84%	
9/29/2010	28.91	7.65	6.80	9.74	33.59	10.20	7.48	81.73	91.75	81%	
9/30/2010	29.53	8.16	6.47	7.19	36.18	13.61	6.91	93.46	106.94	90%	
10/1/2010	27.07	6.68	6.58	5.20	29.46	8.08	7.00	83.91	92.78	89%	
10/2/2010	26.23	6.11	6.62	7.69	31.27	9.76	7.11	85.34	108.61	91%	
10/3/2010	25.86	5.71	6.65	3.04	28.55	7.08	7.14	82.10	98.20	90%	
10/4/2010	28.04	6.72	6.90	8.24	32.57	9.05	8.18	74.60	87.54	89%	
10/5/2010	28.81	6.89	6.83	7.19	33.02	10.71	8.00	72.84	83.41	89%	
10/6/2010	29.44	7.30	6.59	5.16	33.33	9.77	7.30	76.33	90.18	94%	
10/7/2010	29.43	7.25	6.66	14.29	32.75	9.50	7.31	76.26	91.66	95%	
10/8/2010	28.77	7.11	6.51	3.99	33.08	9.84	7.05	79.63	93.66	96%	
10/9/2010	28.78	7.31	6.47	4.17	32.12	9.47	6.90	85.42	99.26	98%	
10/10/2010	27.43	6.54	6.36	4.29	31.20	8.63	6.86	84.93	103.80	98%	
10/11/2010	27.52	6.30	6.45	3.76	33.05	8.60	7.23	79.05	101.14	93%	
10/12/2010	26.54	N/A	6.40	N/A	29.19	N/A	6.83	76.03	86.49	0%	
10/13/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
10/14/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
10/15/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
10/16/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
10/17/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
10/18/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
10/19/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
10/20/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
10/21/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	Engine was shut down at 8:40 due to lack of low range calibration gas for the Stack Exhaust CEMS monitor. Data is missing from 16:02 to 17:06.
10/22/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
10/23/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
10/24/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
10/25/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
10/26/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
10/27/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
10/28/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
10/29/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
10/30/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
10/31/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
11/1/2010	28.67	6.50	7.49	3.13	31.86	9.42	8.49	75.34	96.94	0%	Note 2.
11/2/2010	28.19	6.54	7.54	4.81	33.32	9.67	8.06	74.82	83.23	89%	

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Validated Daily 15-Minute Block Average
Daily Average and Maximum Emissions Summary Data from CEMS
Plant 1 - Catalytic Oxidizer and Selective Catalytic Reduction

Date	Avg. Engine Exhaust NOx @15% O2 (ppmvd)	Average Stack Exhaust		Maximum Ammonia Slip	Maximum Engine Exhaust NOx @15% O2 (ppmvd)	Maximum Stack Exhaust		Average Engine Load (%)	Max Engine Load (%)	Average Fuel Ratio (% DG)	Notes
		NOx @15% O2 (ppmvd)	CO @15%O2 (ppmvd)			NOx @15% O2 (ppmvd)	CO @15%O2 (ppmvd)				
11/3/2010	30.47	8.48	7.30	6.92	34.59	10.70	8.08	84.85	107.53	95%	
11/4/2010	31.14	8.99	7.19	7.27	34.38	10.70	7.68	91.85	109.16	93%	
11/5/2010	30.89	8.88	7.14	5.73	34.94	11.50	8.30	89.41	105.72	98%	
11/6/2010	28.41	7.19	7.19	6.18	32.85	10.10	8.08	85.70	96.36	88%	
11/7/2010	28.75	7.39	7.16	4.18	33.17	9.76	8.08	87.11	104.47	90%	
11/8/2010	30.20	8.10	6.93	5.35	37.51	13.37	8.61	90.50	105.21	48%	
11/9/2010	29.42	7.56	6.90	5.04	32.09	9.39	7.46	81.89	96.84	88%	
11/10/2010	27.07	6.11	7.01	2.81	29.85	8.39	7.61	79.84	97.91	92%	
11/11/2010	31.51	8.89	6.60	7.53	36.58	13.76	7.47	83.93	94.48	92%	
11/12/2010	31.50	8.90	6.86	5.30	37.28	13.42	7.62	88.38	102.32	98%	
11/13/2010	30.19	8.12	6.83	7.52	32.92	9.48	7.38	88.97	98.93	92%	
11/14/2010	28.00	6.92	7.06	6.65	32.41	8.95	7.98	80.73	91.53	90%	
11/15/2010	29.03	7.45	6.94	5.45	33.72	10.72	7.72	80.10	92.11	86%	
11/16/2010	28.04	7.06	6.87	3.45	43.68	13.94	7.92	88.64	102.38	0%	Note 2.
11/17/2010	24.94	5.16	7.08	1.84	26.49	6.38	7.76	82.87	89.68	0%	Note 2.
11/18/2010	25.33	5.25	7.09	4.72	28.62	7.14	7.74	83.83	102.51	0%	Note 2.
11/19/2010	26.67	6.58	7.00	4.28	32.24	12.23	7.82	84.51	95.55	73%	
11/20/2010	26.91	6.40	6.92	3.96	32.90	10.08	7.68	88.49	95.64	90%	
11/21/2010	26.92	6.21	7.00	3.63	31.24	8.02	7.93	79.79	91.55	91%	
11/22/2010	28.97	7.23	6.83	3.81	32.02	8.49	7.64	80.99	98.00	94%	
11/23/2010	28.19	6.83	6.65	3.49	31.73	9.26	7.24	84.08	97.69	98%	
11/24/2010	29.29	7.56	6.63	7.10	33.61	9.78	7.18	90.65	106.51	98%	
11/25/2010	31.81	8.98	6.51	5.52	34.83	10.43	7.06	90.37	96.97	0%	Note 2.
11/26/2010	33.06	9.83	6.51	5.39	36.68	12.59	7.11	90.34	100.05	94%	
11/27/2010	31.95	9.09	6.49	7.26	36.87	11.96	7.01	88.59	97.10	92%	
11/28/2010	31.77	8.99	6.55	7.36	35.35	11.16	7.46	85.58	96.93	93%	
11/29/2010	30.94	8.22	6.68	3.65	34.51	9.98	7.49	83.60	97.89	0%	
11/30/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
12/1/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
12/2/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
12/3/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
12/4/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
12/5/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
12/6/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
12/7/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
12/8/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
12/9/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
12/10/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
12/11/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
12/12/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
12/13/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
12/14/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	Engine offline on 11/29/10 at 15:29 through 12/29/10 at 11:57.
12/15/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
12/16/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
12/17/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
12/18/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
12/19/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
12/20/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
12/21/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
12/22/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
12/23/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
12/24/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
12/25/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
12/26/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
12/27/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	

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Validated Daily 15-Minute Block Average
Daily Average and Maximum Emissions Summary Data from CEMS
Plant 1 - Catalytic Oxidizer and Selective Catalytic Reduction

Date	Avg. Engine Exhaust NOx @15% O2 (ppmvd)	Average Stack Exhaust NOx @15% O2 (ppmvd)	CO @15%O2 (ppmvd)	Maximum Ammonia Slip	Maximum Engine Exhaust NOx @15% O2 (ppmvd)	Maximum Stack Exhaust NOx @15% O2 (ppmvd)	CO @15%O2 (ppmvd)	Average Engine Load (%)	Max Engine Load (%)	Average Fuel Ratio (% DG)	Notes
12/28/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
12/29/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	NOx probe at Engine Exhaust offline. The engine was not out of compliance and
12/30/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	continued to run despite high NOx at the stack exhaust.
12/31/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
1/1/2011	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	After restart of the system on 12/29/10, plant operators had isolated and not checked the
1/2/2011	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	urea injection system. Once checked, the urea supply line was isolated, the urea pump
1/3/2011	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	noisy, the air supply to the injection lance was isolated, and the urea filter housing was
1/4/2011	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	leaking. Johnson Matthey replaced the #1 urea pump on 1/13/11 (Note 4).
1/5/2011	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	Engine offline to relocate engine exhaust NOx probe and replace umbilical line.
1/6/2011	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
1/7/2011	31.43	7.75	7.43	3.34	32.61	8.39	7.76	104.77	107.37	96%	Urea injection was not turned on until 1 hour after engine start-up, data for the hour when the urea system was not online plus 30 minutes of start-up time is excluded from the data set (Note 3).
1/8/2011	31.05	7.35	7.63	2.57	32.70	8.42	8.05	102.22	106.83	95%	
1/9/2011	30.36	7.13	7.16	1.87	33.10	9.12	7.84	88.25	103.01	90%	
1/10/2011	30.98	7.45	7.02	2.26	34.84	9.52	7.50	84.08	96.68	94%	
1/11/2011	32.83	8.21	7.13	2.66	38.26	12.38	7.97	93.99	109.26	85%	
1/12/2011	31.94	7.33	7.70	1.96	34.05	9.25	8.22	100.93	107.27	96%	
1/13/2011	30.20	6.29	7.72	1.79	32.40	7.88	8.77	95.71	108.38	96%	
1/14/2011	32.85	7.97	7.59	2.64	35.06	9.50	8.06	104.41	108.41	96%	
1/15/2011	31.76	7.65	7.52	2.30	34.36	9.47	8.40	99.59	108.97	95%	
1/16/2011	30.89	7.16	8.14	2.01	32.24	8.08	8.73	103.93	110.94	98%	
1/17/2011	29.99	6.82	7.76	2.13	35.39	9.30	8.56	96.90	105.58	81%	
1/18/2011	29.70	6.77	7.59	2.49	32.44	8.50	8.38	94.12	106.01	90%	
1/19/2011	27.21	4.94	7.35	1.59	31.53	7.73	8.14	84.34	103.41	93%	
1/20/2011	30.55	7.39	7.21	13.98	35.22	11.59	7.93	86.34	101.04	91%	
1/21/2011	29.15	6.87	7.51	3.58	33.64	9.89	8.38	87.00	93.08	98%	
1/22/2011	26.97	5.23	7.45	1.60	30.15	7.37	8.44	85.37	96.58	97%	
1/23/2011	29.30	6.81	7.15	2.33	32.08	8.56	7.96	84.82	96.24	98%	
1/24/2011	29.55	6.73	7.01	2.49	32.13	8.12	8.05	78.79	92.24	87%	
1/25/2011	29.54	6.13	7.54	2.68	32.04	7.78	8.41	70.52	85.60	70%	
1/26/2011	31.52	7.78	6.99	3.18	34.94	9.54	8.05	87.50	108.13	86%	
1/27/2011	30.33	7.41	7.15	2.34	33.96	8.76	7.77	86.61	106.21	96%	
1/28/2011	29.42	6.73	7.56	2.37	32.77	8.88	8.16	92.70	107.40	96%	
1/29/2011	26.64	4.59	7.83	0.96	29.23	6.26	8.37	88.57	97.08	96%	
1/30/2011	26.98	5.02	7.08	1.03	28.37	6.04	7.56	80.00	86.47	94%	
1/31/2011	28.13	5.45	7.26	2.24	36.23	10.64	8.80	75.28	91.23	77%	
2/1/2011	28.53	5.75	7.32	2.79	32.14	7.92	8.48	73.98	84.95	87%	
2/2/2011	33.07	7.86	7.06	5.22	38.46	11.02	8.07	71.26	78.57	88%	
2/3/2011	29.41	6.08	7.14	1.60	32.47	7.39	7.71	80.11	87.92	94%	
2/4/2011	28.76	5.60	7.90	1.42	32.21	7.37	8.90	92.09	104.87	93%	
2/5/2011	27.35	5.33	7.83	0.93	29.39	6.31	8.46	88.44	96.01	91%	
2/6/2011	26.70	4.30	7.87	2.09	28.72	6.37	8.61	80.20	84.32	83%	
2/7/2011	28.87	6.01	7.70	1.25	30.14	7.24	8.18	80.59	84.04	0%	
2/8/2011	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
2/9/2011	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
2/10/2011	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	Engine offline 2/7/11 9:48 to 2/14/11 17:08 to change DGCS carbon media.
2/11/2011	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
2/12/2011	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
2/13/2011	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
2/14/2011	29.60	7.32	6.76	5.31	31.62	10.02	7.71	90.54	97.53	0%	Note 2.
2/15/2011	29.97	7.00	7.40	2.70	34.01	8.68	7.93	95.74	106.86	98%	
2/16/2011	29.37	6.58	7.55	2.65	33.09	8.65	8.24	98.00	105.83	98%	
2/17/2011	32.25	8.07	7.48	3.30	34.04	9.81	8.23	104.74	111.50	98%	
2/18/2011	31.24	7.53	7.82	2.31	33.91	9.15	8.54	106.56	111.92	98%	

July 2011

Validated Daily 15-Minute Block Average
Daily Average and Maximum Emissions Summary Data from CEMS
Plant 1 - Catalytic Oxidizer and Selective Catalytic Reduction

Date	Avg. Engine Exhaust NOx @15% O2 (ppmvd)	Average Stack Exhaust NOx @15% O2 (ppmvd)	Average Stack Exhaust CO @15%O2 (ppmvd)	Maximum Ammonia Slip	Maximum Engine Exhaust NOx @15% O2 (ppmvd)	Maximum Stack Exhaust NOx @15% O2 (ppmvd)	Maximum Stack Exhaust CO @15%O2 (ppmvd)	Average Engine Load (%)	Max Engine Load (%)	Average Fuel Ratio (% DG)	Notes
2/19/2011	30.92	7.36	7.55	2.81	33.90	9.76	8.31	102.93	110.40	98%	
2/20/2011	29.65	6.85	7.06	2.09	32.21	8.18	7.83	91.32	103.02	96%	
2/21/2011	29.49	6.57	6.81	3.01	34.00	8.82	7.57	81.64	91.69	93%	
2/22/2011	29.82	6.69	6.69	1.67	32.47	8.87	7.38	82.92	94.52	98%	
2/23/2011	31.09	7.21	7.18	1.64	33.45	8.16	7.92	99.43	109.78	98%	
2/24/2011	31.65	7.30	7.47	1.73	34.03	8.36	8.49	102.95	110.44	98%	
2/25/2011	33.13	8.13	7.39	4.04	34.16	9.47	7.71	106.44	111.02	0%	
2/26/2011	31.50	7.57	7.07	2.48	33.15	8.55	7.76	101.16	110.09	98%	
2/27/2011	33.42	8.34	6.97	2.93	36.58	10.04	7.36	100.53	108.17	98%	
2/28/2011	31.80	7.81	6.86	3.10	36.29	9.77	7.51	90.10	107.79	95%	
3/1/2011	30.14	6.79	7.14	2.65	32.51	9.02	7.88	91.95	105.72	98%	
3/2/2011	29.41	6.16	7.89	2.23	37.66	8.02	8.71	97.69	107.61	0%	Note 2.
3/3/2011	27.86	5.47	8.17	1.59	29.72	6.73	8.74	96.80	107.33	94%	
3/4/2011	28.83	6.08	8.46	1.39	30.85	7.23	8.87	102.94	110.40	98%	
3/5/2011	29.09	6.35	8.42	2.79	31.91	8.58	9.06	102.87	109.47	98%	
3/6/2011	26.63	5.01	7.89	1.43	28.70	6.04	8.86	91.24	102.92	95%	
3/7/2011	27.81	6.04	7.38	3.36	32.91	9.41	8.20	89.45	100.37	98%	
3/8/2011	28.03	6.00	7.69	2.04	30.45	7.55	8.68	91.40	103.44	98%	
3/9/2011	27.70	5.78	7.74	1.63	28.67	6.37	8.21	91.79	96.55	0%	Note 2.
3/10/2011	26.98	5.87	7.92	2.28	28.96	7.08	8.73	93.76	101.35	0%	Note 2.
3/11/2011	27.73	6.20	7.84	2.26	29.32	7.36	8.68	93.95	102.83	98%	
3/12/2011	28.37	6.49	7.67	2.08	29.98	7.32	8.58	94.09	106.19	97%	
3/13/2011	28.04	6.55	7.24	2.32	30.87	7.94	7.92	86.38	94.42	96%	
3/14/2011	29.04	7.21	7.16	5.04	31.84	9.62	7.70	87.02	93.44	0%	High NOx at the stack exhaust was due to a plugged urea injection lance (Note 4).
3/15/2011	28.24	6.44	7.60	2.99	29.70	7.59	8.40	92.96	101.85	98%	
3/16/2011	28.44	6.31	8.23	3.16	30.97	7.93	8.93	102.24	112.00	0%	
3/17/2011	29.40	8.59	8.11	2.34	31.30	10.76	8.56	102.10	107.70	0%	High NOx at the stack exhaust was due to a plugged urea injection lance (Note 4).
3/18/2011	29.51	8.20	8.84	2.54	31.79	11.09	32.82	102.78	110.18	98%	
3/19/2011	29.74	8.35	8.26	1.65	30.91	9.75	8.78	104.74	110.34	98%	
3/20/2011	27.83	6.94	7.72	1.31	30.84	9.39	8.77	93.75	104.95	95%	
3/21/2011	28.21	7.40	7.07	1.89	32.24	11.51	7.72	86.26	93.65	96%	
3/22/2011	29.87	8.50	7.62	2.62	33.20	11.89	8.58	97.16	108.53	98%	High NOx at the stack exhaust was due to adjustments to the SCR system by the system vendor (Note 3).
3/23/2011	29.24	7.54	8.08	1.31	31.75	9.71	8.65	101.83	108.03	98%	
3/24/2011	30.65	8.85	7.80	1.82	33.25	11.38	8.64	104.13	111.30	98%	
3/25/2011	30.25	8.63	8.04	2.64	31.35	10.14	28.89	105.44	111.08	98%	
3/26/2011	29.18	7.42	7.68	1.61	31.17	9.73	8.31	102.28	109.88	97%	
3/27/2011	27.38	6.34	7.25	1.56	30.41	9.39	8.12	91.24	100.63	96%	
3/28/2011	28.92	7.97	6.98	1.78	30.98	9.74	7.51	91.25	100.68	98%	
3/29/2011	28.50	7.37	7.33	1.65	30.23	9.67	7.97	95.03	105.40	98%	
3/30/2011	29.35	8.24	7.90	2.25	31.85	11.35	8.37	103.55	110.65	98%	
3/31/2011	29.44	8.39	8.09	2.01	30.77	10.27	8.43	106.76	111.47	98%	

Notes:

(1) Urea injection setpoints were modified on June 8, 2010. Therefore, stack exhaust NOx data prior to June 8, 2010 is not included in the analysis of the SCR system and is not provided in this table.

(2) The first 30 minutes after start-up of the engine are excempt from Amended Rule 1110.2. Data was excluded where NOx at the stack exhaust exceeded 11 ppmvd during engine start-up.

(3) Data was excluded where NOx at the stack exhaust exceeded 11 due to system adjustments to the urea injection system.

(4) Data was excluded where operational issues occurred from 7/1/10-7/4/10, 12/29/10-1/4/11, 3/14/11, 3/17/11, and 3/22/11.

(5) Values shown are average or maximum values (as indicated) for each calendar day and may not all occur at the same time within the day.

(6) N/A indicates that data was not available because the engine was offline.

July 2011

APPENDIX C-4:

Technical Memorandum:
OCSD Catalytic Oxidizer/SCR Pilot Study:
Ammonia Sampling and Calculation Methods

Technical Memorandum

Date: July 31, 2011

To: File

From: Kit Liang ; Daniel Stepner, Malcolm Pirnie, WHI

Re: OCSD Cat Ox/SCR Pilot Study: Ammonia Sampling and Calculation Methods
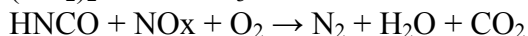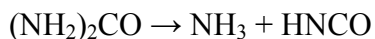
Project No.: 0788-187

Introduction

To meet the South Coast Air Quality Management District (SCAQMD) Rule 1110.2 limit for oxides of nitrogen (NOx), the Orange County Sanitation District (OCSD) installed a urea-based selective catalytic reduction (SCR) system after the internal combustion (IC) engine exhaust and catalytic oxidizer (Cat Ox) at the Plant 1 Engine 1. The SCR system was designed to remove NOx through a chemical reaction between ammonia (provided by the urea ($(NH_2)_2CO$)) and the NOx on the SCR catalyst surface. During this process, a small amount of unreacted free ammonia (NH_3) or "*ammonia slip*" can be emitted into the exhaust gas. The objective of this memorandum is to discuss the reactions leading to ammonia slip, and a comparison of the different ammonia estimation methods.

SCR Overview

SCR is an air pollution control method that reduces the NOx emissions resulting from fossil fuel combustion through a chemical reaction between the NOx in the exhaust stream and NH_3 provided by the injection of ammonia or urea. The reaction is facilitated by a catalyst to form nitrogen and water vapor.

Engine 1 at OCSD Plant 1 is a four-stroke cycle engine, fueled with a blend of digester gas and natural gas. A Johnson Matthey® SCR system is located downstream of the engine and after a catalytic oxidizer. Aqueous urea is injected into the engine exhaust duct upstream of the SCR catalyst. Once urea is injected into the engine exhaust stream, it breaks down into ammonia and other constituents. Hydrolysis of the urea on the face of the catalyst generates more ammonia. This ammonia reagent reacts with the NOx in the stack emissions, and with the aid of a catalyst, reduces the NOx to harmless constituents: nitrogen, water vapor, and carbon dioxide. The ammonia can also react with sulfur dioxide (SO_2) and sulfur trioxide (SO_3) in secondary reactions to produce ammonium bisulfate (NH_4HSO_4) and ammonium sulfate ($(NH_4)_2SO_4$). The equations for these reactions are as follows:
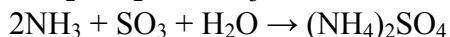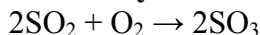
Urea Reaction

$(NH_2)_2CO \rightarrow NH_3 + HNCO$

$HNCO + NOx + O_2 \rightarrow N_2 + H_2O + CO_2$

Ammonia Reaction

$NH_3 + NOx + O_2 \rightarrow N_2 + H_2O + CO_2$

Secondary Reactions:

$2SO_2 + O_2 \rightarrow 2SO_3$

$2NH_3 + SO_3 + H_2O \rightarrow (NH_4)_2SO_4$

$NH_3 + SO_3 + H_2O \rightarrow NH_4HSO_4$
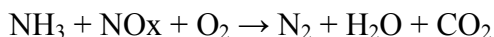
The ammonia/NOx reaction is optimal between 750°F and 850°F. The amount of NOx in the engine exhaust gas varies with the engine load, and fuel type or fuel blend (in this case, the proportion of digester gas and natural gas). In the SCR system, the injection of the urea is controlled based on process variables, including engine operation (on/off), engine load (i.e., process flow), and NOx concentration measured at the exhaust stack; and the quantity of urea to be injected is roughly proportional to the NOx being reduced and the volume of exhaust flow.

It is important not to inject more urea than necessary in order to keep the unreacted, unconsumed, free ammonia levels to a minimum. Excess free ammonia can occur when:

- Ammonia or urea, is over-injected into the exhaust stream,
- The temperature of the gas is too low for the ammonia to react, or
- The catalyst is degraded.

Significantly high levels of free ammonia in the exhaust stack gases can often be identified by a visible plume above the stack. Not only can the excess ammonia exceed permitted limits (ammonia is regulated by SCAQMD), but it also indicates that more ammonia or urea than needed was injected, resulting in a greater urea supply and storage capacity than actually needed to control the NOx emissions. In addition, compounds such as the sulfates formed in the secondary reactions presented above, in which free ammonia reacts with sulfur compounds, have been shown to result in the corrosion of downstream equipment and to cause line plugging. This has been discussed in the literature in particular for fuels with high sulfur content, such as coal. The general range of temperatures for the sulfate formation is reported to range from 390 to 450 °F for medium to low sulfur fuels.

**Johnson Matthey® SCR Urea Control System**

The goal of the SCR control system is to balance urea injection to reduce NOx concentration in the exhaust gas to below 11 ppm with a minimum amount of unconsumed or free ammonia. The maximum concentration of free ammonia allowed for this Pilot Study Research Permit is 10 ppm NH_3.

The urea injection control system determines the correct rate of urea according to the engine load signal and the urea versus engine load map programmed into the control system. The load map, which correlates the urea injection rate to the engine load, was programmed during commissioning of the system by Johnson Matthey®. This load map allows the controller to interpolate between the prescribed load values and urea injection

rate to generate an overall curve of urea injection vs. engine load. As the engine is brought to load and as the engine load changes, urea flow rate is modulated by the flow control valve according to the determined urea injection rate. In addition to the load map control, the injection system also receives the NOx concentration at the stack outlet from the continuous emissions monitoring system (CEMS) stack exhaust NOx probe. This NOx signal is then used to increase the actual urea injection rate by a set percent *bias* as needed in order to fine tune the NOx emission rate.

As the engine was operated under varying loads during load mapping, Johnson Matthey® measured the NOx concentration with a portable chemiluminescent analyzer and the ammonia slip with Draeger® tubes at the SCR catalyst outlet. The purpose of these measurements was to develop a plot (map) of urea injection rate versus engine load that would meet NOx and ammonia slip emissions requirements. The urea injection rate versus engine load map is provided in Figure 1 below. The solid line represents the true set points for urea injection rate based on engine load set by Johnson Matthey® on June 8, 2010. The dashed line represents the urea injection rate with the injection rate bias to increase the urea injection rate based on the NOx outlet emissions.

Figure 1:
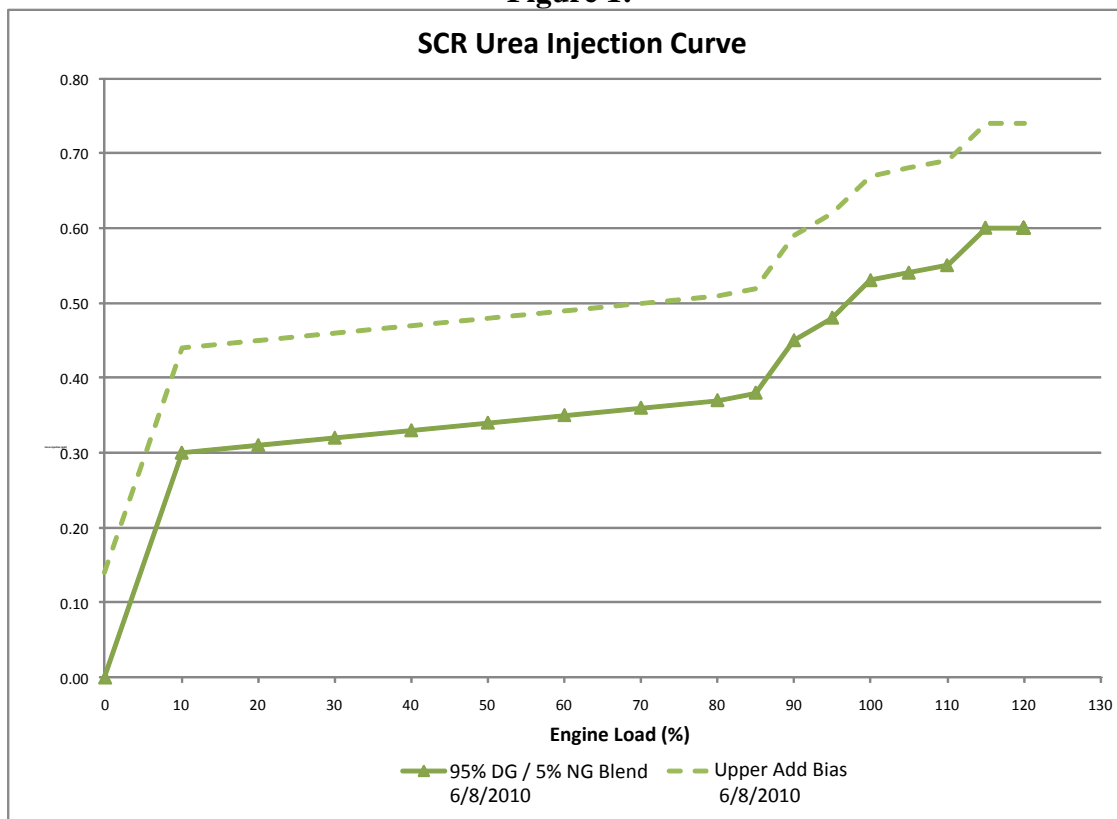
Methods of Estimating Ammonia Concentration

Three methods were used for determining ammonia concentration:

- On-site field measurement using Draeger® or Sensidyne® tubes (free ammonia),
- SCAQMD Method 207.1 (free ammonia), and
- Estimated total ammonia calculation method using inlet and outlet NOx CEMS concentration and urea injection rate.

Draeger® and Sensidyne® Tubes

Free ammonia was measured in the field periodically using Draeger® and Sensidyne® tubes. A Draeger® or Sensidyne® tube is a glass vial filled with a chemical reagent that reacts and changes color in the present of a targeted chemical. When a gas is pumped through the tube, the discoloration of the reagent is read against a scale on the outside of the tube to indicate the concentration of the chemical.

During the field sampling, a Tedlar® bag was filled with exhaust gas from the sample port located after the SCR outlet. The exhaust gas was pulled through the Draeger® or Sensidyne® tube; and the concentration of free ammonia was read against the scale on the tube. Two ranges of Draeger® tubes were used to detect ammonia: 0.25-3 ppm (low-scale) and 2-30 ppm (high-scale). If ammonia was detected and saturated the low-scale tube, the high-scale tube was used.

Estimated Ammonia Calculation Method

Using the estimated ammonia calculation formula, total ammonia is calculated based on the NOx inlet and NOx outlet concentrations, urea injection rate, and total exhaust flowrate. Data from the CEMS system and operational data from the data acquisition system (DAS) were used for the calculations. The NOx and urea react on a 1:2 basis. Therefore, the amount of urea reacted is theoretically equal to two times the amount of NOx reduced by the SCR.

$$Ammonia = \left[Urea\ Fed - \frac{NOx\ in - NOx\ out}{2}\right] \times CF$$

The CEMS vendor, Cemtek Environmental, Inc., programmed the following formula to calculate ammonia slip:

$$Ammonia = \left[\frac{(2 \times \rho \times Urea\ Flow\ Rate \times \%\ wt\ urea)}{Urea\ Molecular\ Weight} - \frac{Dry\ Gas\ Flow\ Rate}{29} \times \frac{(NOx\ in - NOx\ out)}{10^6}\right]$$
$$\times \frac{10^6}{Dry\ Gas\ Flow\ Rate/29} \times CF$$

The *Dry Gas Flow Rate* is calculated using the following equation:

$$Dry\ Gas\ Flow\ Rate = \big((Fuel\ Flow \times Fuel\ GCV) \times Fuel\ Factor\big) \times (20.9/(20.9 - \%\ O2))$$

Where the following units apply:

- *Urea Flow Rate*: gallon per hour (gal/hr)
- *NOx in*, *NOx out* (inlet and outlet NOx concentration): parts per million (ppm$_c$) @ 15% O_2
- *Dry Gas Flow Rate*: pounds per hour (lbs/hr)
- *CF*: Correction factor (derived annually)
- *Fuel Flow Rate*: dry standard cubic feet of fuel (dscf)
- *Fuel GCV* (gas constant value): Btu value of the fuel / dscf
- *Fuel Factor*: dscf @ 0% O_2 / million Btu value of the fuel
- $\rho\left(\frac{H2O}{Urea}\right) = 68.9\frac{lb}{ft^3} \text{ or } 9.21\frac{lb}{gal}$ *with urea @ 32.5% wt @ 4°C*
- $Urea\ Molecular\ Weight = 60.0553\frac{lb}{lb}mol$

The estimated ammonia calculation method allows for adjustment of the ammonia estimation through use of the correction factor, CF. Without accounting for secondary reactions through consumption of free ammonia with other compounds in the engine exhaust gas, such as sulfates, the method actually estimates total ammonia (i.e., free ammonia plus combined ammonia). The method does allow for use of a correction factor which could be applied to account for these secondary reactions. During the pilot test, no correction factor for potential side reactions was programmed into the calculation, and the CF was assumed equal to 1.

SCAQMD Method 207.1
SCAQMD Method 207.1 is the regulatory approved method for determining free ammonia emissions from stationary sources. This method is a wet chemistry method in which the samples are collected from impingers containing a sulfuric acid solution. The samples are then analyzed by an ion selective electrode.
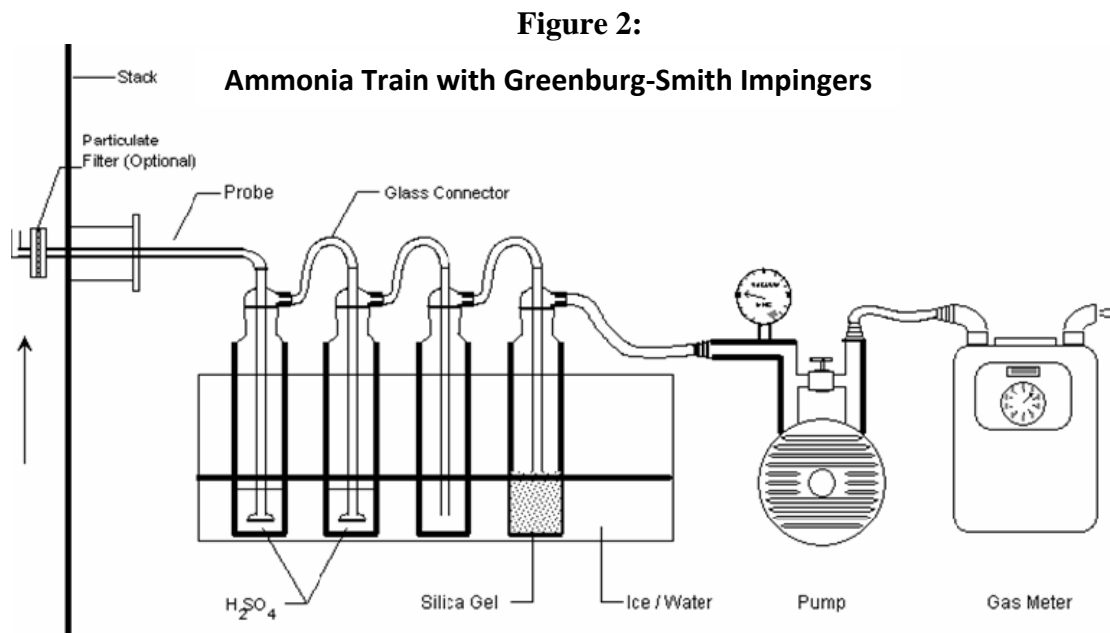
Figure 2 provides a standard setup for the SCAQMD Method 207.1. During the initial period of the pilot testing, the testing firm, SCEC, performed ammonia sampling at the stack exhaust for three loads on April 7 and 8, 2010.

Discussion
Table 1 presents a comparison of the free ammonia concentrations determined using the Draeger® and Sensidyne® tubes, the free ammonia concentrations determined using SCAQMD Method 207.1, and the theoretical total ammonia calculations. The ammonia concentration values were based on the same recorded 15-minute average CEMS data for all three methods.

While the field measurements taken with the Draeger® and Sensidyne® tubes show no measurable free ammonia, the total ammonia calculation method based on the CEMS data did provide a calculated value of total ammonia (free plus combined ammonia). Likewise, the results using SCAQMD Method 207.1 on 4/7/2010, 4/8/2010, and 5/10/2011 were less than 1 ppm of free ammonia, while the estimated total ammonia method calculated values using the CEMS data were noticeably higher.

Figure 2:

Ammonia Train with Greenburg-Smith Impingers

Stack

Particulate Filter (Optional)

Probe — Glass Connector

H_2SO_4 Silica Gel   Ice / Water   Pump   Gas Meter

The ammonia calculation method is dependent on the NOx inlet and NOx outlet concentrations, and the urea injection rate, which is continuously changing based on the engine load and the NOx outlet concentration. The difference between the estimated total ammonia calculation method and the other techniques may be due to the conservative nature of the estimated method for determining ammonia slip, since it assumes that the ammonia from the urea consumes only NOx. There is the potential for ammonia molecules to also be consumed in other secondary reactions in the exhaust stream, such as those with sulfur compounds (forming combined ammonia). However, no correction factors were applied to account for the consumption of ammonia in secondary reactions. Without a correction factor to account for these secondary reactions, the calculation method essentially estimates total ammonia, or the sum of free and combined ammonia.

Engine load fluctuates with time. When the IC engines are set to a base load, it was observed that the actual engine load fluctuated rapidly by as much as ten percent below the set point. This was found to be typical for the OCSD IC engines. However, since urea injection rate is mapped to engine load, rapid fluctuations in load can result in rapid changes in urea injection rates. Rapidly changing urea injection rates, instead of steady rates with smooth transitions, can also lead to inaccuracies in the ammonia calculation.

Table 1:
Ammonia Concentration Sampling Event Summary

Date	Engine Load	Draeger® and Sensidyne® Tube (Free Ammonia) (ppmv) [1]	Calculated Value (Total Ammonia) (ppmv) [2]	SCAQMD Method 207.1 (Free Ammonia) (ppmv)
4/7/2010 & 4/8/2010	65%	<MDL	1.66	0.12
	90%			0.18
	105%			0.43
4/21/2010	110%	<MDL	0.09	N/A
4/29/2010	90%	<MDL	0.00	N/A
5/6/2010	94%	<MDL	2.18	N/A
5/19/2010	100%	<MDL	2.54	N/A
6/29/2010	100%	<MDL	0.97	N/A
7/28/2010	100%	<MDL	0.63	N/A
8/12/2010	95%	<MDL	2.50	N/A
11/4/2010	100%	<MDL	4.95	N/A
1/12/2011	100%	<MDL	0.32	N/A
2/24/2011	100%	<MDL	0.09	N/A
5/10/2011	70%	<MDL	1.12	0.37
	90%		1.60	0.31
	110%		3.12	0.38

Notes: 1. Free ammonia field measurements were taken at the SCR outlet using 0.25-3 ppm range and 2-30 ppm range Draeger® tubes. On 5/10/2011, additional free ammonia field measurements were taken at the stack exhaust using Sensidyne® tubes with the same measurement results as the Draeger® tubes.
2. Total ammonia was determined based on the theoretical calculation which uses NOx inlet and NOx outlet of the Cat Ox/SCR system and the urea injection rate. The calculated value reported is based on the 15-minute block average from the CEMS for the time period when the exhaust gas sample was taken for the field measurement. No correction factor was applied.
3. <MDL – less than Method Detection Limit.
4. N/A indicates not applicable. No data was taken using Method 207.1 during these field measurement events.

Conclusions and Recommendations

Upon review of the field measurements for free ammonia and calculated values for total ammonia, the estimated total ammonia calculation method appears to overestimate the free ammonia in the SCR outlet over both the field sampling method and SCAQMD Method 207.1. This may be partially due to the varying urea injection rates. In addition, the estimated ammonia calculation method does not account for other potential ammonia reactions which may consume the unreacted ammonia, such as those with sulfur compounds in the exhaust gas. Without the application of a correction factor to account for these, the calculation method actually estimates total ammonia (free plus combined ammonia). However, this may be useful as a tool to prompt a field measurement to confirm free ammonia concentrations in the exhaust gases. Additional sampling of the

exhaust emissions could be performed to establish a correction factor for the theoretical ammonia slip calculation method. The presence of sulfur dioxide and sulfur trioxide in the exhaust gas before the SCR, and ammonium sulfate and ammonia bisulfate detected in the exhaust gas after the SCR, can indicate that secondary reactions are taking place due to the injection of urea.

Further study is needed to determine the potential for detrimental effects of ammonia sulfates formation in equipment downstream of the SCR system. For example, after two years of Engine 1 operation using the Cat Ox/SCR system with DGCS, it is recommended that OCSD examine the heat recovery boiler for any equipment deterioration or noticeable particulate buildup.

Although little, if any, free ammonia was found during the pilot study of the SCR system, it is recommended that the OCSD perform additional and routine testing for free ammonia during varying loads and fuel blends over a period of time. Additional testing for free ammonia can provide data to verify that the SCR system does not produce ammonia slip from the stack exhaust under the range of operating conditions for a given mapped urea injection versus engine load set point.

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